COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

```
In the Matter of:                     )
                                      )
Preparation of the                    ) Docket No.
2007 Integrated Energy Policy Report  ) 06-IEP-1M
                                      )
Scenario Analyses of California's     )
Electricity System                    )
_____________________________________)
```

CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

MONDAY, JUNE 18, 2007

9:05 A.M.

Reported by:
Peter Petty
Contract No. 150-04-002

COMMISSIONERS PRESENT

Jackalyne Pfannenstiel, Presiding Member

John L. Geesman, Associate Member

ADVISORS PRESENT

Melissa Jones

Timothy Tutt

Kevin Kennedy

STAFF and CONTRACTORS PRESENT

Lorraine White

Bill Knox

Mike Jaske

Richard Lauckhart
Global Energy Solutions

ALSO PRESENT

Steve St. Marie, Staff Advisor
CPUC Commissioner John Bohn

Jacqueline Jones
Southern California Edison Company

Jane Turnbull
League of Women Voters

Robin Smutny-Jones
California Independent System Operator

Wade McCartney
California Public Utilities Commission

Eric Wanless
Natural Resources Defense Council

ALSO PRESENT

Osman Sezgen
Pacific Gas and Electric Company

Claudia Greif, Consultant
California Independent System Operator

I N D E X

I N D E X

P R O C E E D I N G S

9:05 a.m.

ASSOCIATE MEMBER GEESMAN: This is a workshop of the California Energy Commission's Integrated Energy Policy Report. I am John Geesman, the Associate Member of the Integrated Energy Policy Report Committee. To my right is my Staff Advisor, Melissa Jones. To her right, Steven St. Marie, the Staff Advisor to CPUC Commissioner John Bohn. To my left, Kevin Kennedy, Staff Advisor to Energy Commissioner Jeffrey Byron.

Today's topic is the development of scenarios that our staff and contractors have been working on for the past five or six months. Lorraine, do you want to start?

MS. WHITE: Yes, sir, thank you. Good morning, everyone. My name is Lorraine White, the Program Manager for the Integrated Energy Policy Report proceeding. And I'd like to welcome you all to today's workshop, one of many in the 2007 proceeding.

Today's workshop, as Commissioner Geesman has mentioned, is on the scenario analyses conducted by Dr. Mike Jaske and his team related to the electricity system for California.

There's a few logistical things I'd like to go over; most of you already know this. But I do want to let you know that here at the Commission restrooms are out the door to the left, or directly behind the elevators. We also have a snack shop on the second floor under the awning.

In the event of an emergency we would like you all to exit calmly, quietly with the staff. We will be meeting all over at the park just kitty-corner from the Commission here until we get the all-clear sign to return.

For those of you calling in to participate in today's workshop it is not only Webcast that will allow you to see the slide presentations, but we do have a call-in number for those that would actually like to ask questions or make comments about the materials covered today. That number is (800) 857-6618. The passcode to join the teleconference is IEPR, I-E-P-R. I'm the call leader, again, Lorraine White.

Those of you that have called in and would actually like to follow the Webcast along on the website, please go to the Energy Commission's site at www.energy.ca.gov. We look forward to those that have attended here in person to ask questions and engage us in discussions about the materials that Mike will be presenting and the rest of his team on the scenarios that were developed for this proceeding.

The agenda today is pretty meaty. We're going to be going through quite a bit of materials related to the scenarios, themselves; the methods used to develop the assumptions; the way the scenarios were built; the information related to technology; the results that we were able to generate as part of these scenario analyses.

What we think might be some of the consequences that these results indicate; the types of sensitivities we did on these cases; what we think might be the limitations or possible uses for this work and next steps for analyses associated with the proceeding.

And then we hope to, as I mentioned already, get comments and have you ask us questions and engage us in a dialogue about this work.

To put this effort in context the Integrated Energy Policy Report requires the Commission to do a variety of assessments and forecasts related to energy resources in the state; the supply, the demand and price of those resources.

From that analyses, those assessments, we're to develop recommendations and policies to address issues or problems that we've been able to identify.

We are very dependent upon market participants, other agencies to not only gather the information from, but consult with, as we develop these analyses and recommendations.

This work is required to be refreshed essentially every two years, with intervening years being focused mostly on updates or reviews of key topics.

In this particular proceeding most of the base analyses and forecast work will be done through the end of July. We'll really be focused on developing the integrated document, the Committee draft Integrated Energy Policy Report by late August.

We hope to adopt a final Commission Integrated Energy Policy Report on October 24th of this year. That would allow us the opportunity to transmit it within the legislative deadline of

November 1st.

In terms of the next step related to this particular part of the analysis, the scenario work, we're asking parties to provide us comments and/or questions by June 29th related to the materials we're covering today.

The third workshop on this topic, the scenario analysis, will be held on July 9th, just a few weeks from today. Materials presented in that workshop, we're asking for parties to provide comments on by July 20th.

This will allow staff to complete this part of the analysis by late July, early August in time for the Integration workshop we're planning for August 13th.

Information related to this proceeding, of course, can be found on the Commission's website. If you can't find what you're looking for, you can always call me and get any kind of general information about the proceeding.

And then particular to the scenario analyses and the work that's going to be discussed today and on July 9th, I direct people to call Mike Jaske. His information is not only here on this slide, but contained in the notice for this working and the July 9th workshop.

Is there any questions about the material we'll be covering today? With that, Commissioner, I'd like to introduce Mike Jaske.

DR. JASKE: Good morning. For the record my name is Mike Jaske, officially assigned in the Executive Office of the Energy Commission, and affiliated with the energy supply analysis division.

I'd like to explain the nuances between this workshop and the July 9th workshop that Lorraine just mentioned. This workshop is primarily intended on acquainting people with the results, the assumptions, the methods used for this project. We are not expecting extensive comments from parties about what it means, et cetera. That, in fact, is the subject of the July 9th workshop.

So this is really an opportunity for folks to become more familiar with the work and to ask questions, get clarification so that they can, in fact, prepare themselves for submitting comments in about two weeks and participating in that July 9th workshop.

In order to allow it to be as

interactive as possible, given the need to use microphones and transcribe this workshop, I suggest that people from the audience who have questions come up to this microphone in the center and ask those questions at the end of every section.

So corresponding to our agenda today, each of these lettered sections a through h, I've got a little indication in the handouts where that break is. So at the conclusion of any one of these sections I'll give an opportunity for people to ask questions. We won't be too far downstream from the particular slide that may have provoked your thoughts or questioning.

And, of course, to the extent that, Commissioners, I can see you more readily, if you have questions and you're at a microphone, feel free to ask yours, you know, as I go.

I do, as this slide does, want to acknowledge the team that put this project together, both Energy Commission Staff, as well as consultants. In fact, consultants from three organizations. The principal people involved are listed here. This project could not have been completed in the timeframe that it was without this large crew of people who sort of all came together and put their shoulders to the wheel and produced all of this work in only about seven months time.

What we're really trying to do with this project is get a better understanding of all of the ramifications of the actions that we think are necessary to achieve major reductions in greenhouse gas emissions for the electricity sector. That's an important limitation. This is not a holistic analysis of the entirety of all GHG emissions. It is focused only on the electricity sector.

And as I explain various things along the way and toward the end of the presentation, get into the limitations, I'll make sure that some of these implications are better understood.

So, clearly energy efficiency and renewables, a variety of types, are the sort of noncarbon opportunities to pursue. The state has been pursing these through various policies, regulatory actions of the agencies, direct legislation for years. What we are doing in this project is taking those to an even further degree, trying to understand the consequences were they to be implemented at very high levels of penetration.

And then, as the last bullet indicates, organize this project so we can at least begin the process of trading off one element of these strategies versus another.

We have produced over the last several weeks a main report consistent of ten chapters. That was published about two weeks ago. Only late last week were the appendices published and some Excel spreadsheets that are even more detailed than the appendices. And so this workshop is really an opportunity for people to ask questions, to get clarification about a considerable pile of documentation.

We are still in process on two particular subtopics within the overall project. First is the implications of aging power plant retirements, focusing particularly on southern California. That work is still in process. We hope to be able to issue supplemental documentation and be able to talk about that at the July 9th workshop.

And also the impacts on natural gas prices of reduced UEG, utility electric generation natural gas demand. That work is also in process and we anticipate it being documented in the middle of July. And so it will be one of the subjects of the August 13th workshop.

So the word scenarios has been used extensively this morning. What we mean by scenarios, particularly thematic scenarios, as we're calling them, are depicted in these nine cases.

Starting at the top with one that is essentially the current conditions extended into the future. Current conditions meaning the kind of decisions that utility executives might make. Given that there are various kinds of regulatory emphases on efficiency and also on renewables, what decisions might they be making nonetheless.

All the way down through case 5.b., which is very high levels of energy efficiency and high levels of renewables throughout the west.

And some of our documentation previously produced perhaps the vocabulary of the January 29th workshop that laid out something like these same cases, talked about these being the bookends. On the one hand, a very traditional, conservative, conventional generation, sort of resource plan buildout; all the way up to a very aggressive level of efficiency and renewables.

This is also a good time to indicate that these scenarios are configured so that they are evaluated for the entirety of the western interconnection. Sometimes we'll use WECC to describe that, Western Electricity Coordinating Council; although western interconnection is probably a more correct formal term.

And the scenarios, themselves, are sometimes designed for these efficiency and renewables just in California or throughout the west. So typically the A designation on a case means California only. A B designation means throughout the west.

This figure, ES-1, is taken directly from the executive summary; hence its numbering. This is an attempt to sort of lay out how the various cases cover energy efficiency going along the horizontal axis or renewables going up the vertical axis. So the pink dots are approximately where the various cases lie.

You might wonder why, given the emphasis on energy efficiency, particularly in California, why we're at zero in case 1. That has to do with sort of an accounting difficulty, is that once energy efficiency is sort of designated to be committed, it's typical practice for that to be embodied in a load forecast. And you kind of lose track of exactly how much that is. Whereas for renewables, they're discrete generators; you can enumerate them, count them. And so there's an accounting convention issue that case 1 really does not have zero. It's just that it's buried inside the load forecast.

So then each of these other cases are presumed to have higher levels of energy efficiency and renewables. And eventually you work yourself up to case 5A in the upper right corner as the highest levels of both of those for California.

Figure ES-2, again from the executive summary, is a way to get a quick glance at what the results are. Here we're comparing the resource mix in 2020, which is what any one of these stacked bars represents. Across all the nine thematic scenarios.

So the bars from left to right represent increasing levels of energy efficiency and renewables. So energy efficiency shows itself as pink on the color charts. And pink is higher in various of these scenarios.

Renewables of various kinds have their own color. So wind, distinct from geothermal, as an example. Clear message here is that gas-fired generation, which is the green slash bars, is shrinking as you go from left to right across all these cases.

So there's a substitution going on between energy efficiency and renewables and photovoltaic increasing and natural gas-fired generation decreasing. Clearly this is what one would expect. That's how the scenarios are designed. Really what this slide is telling us is something about magnitude of those effects.

Figure ES-3 is an overview of carbon responsibility, again for 2020, across all the cases. And there are three elements to carbon responsibility as has been computed in this project.

The blue one down at the bottom is that carbon produced directly by power plants located within California. The sort of reddish colored bar is carbon emitted by power plants that w call remote. And remote are those located outside of California, but owned by California utilities or under a long-term contract.

So, for example, IPP is a plant outside of California, owned by Los Angeles with shares by some others. And that's part of California carbon responsibility.

Lastly, at the top is carbon responsibility for imports. And imports here are not including remote. They are short-term market purchases for which it's difficult to make an attribution to a particular plant.

And if you were to examine the relative size of each of these segments of each bar, the blue within California plant emissions, clearly going down, generally from left to right, as more efficiency and more renewables.

The remote portion nearly constant across all those scenarios. And a great deal of variability in the carbon emissions associated with imports.

In fact, if you were to go back to the previous slide, you would -- which it was harder to see, imports, themselves, are jumping up and down, you know, just about proportional to these carbon responsibility portions.

So imports vary a great deal in these

results. Has important consequences for how to think about California carbon responsibility and the source-based versus loadbase issues that are underway in the regulatory community practically as we speak.

This next slide, ES-5, is a way of showing results in terms of costs. We have again the nine basic scenarios. There are two kinds of costs here. The left-hand group of bars are what we call system costs. The right-hand group of bars are production costs. Production costs are the things normally associated with variable cost of production.

So fuel the largest. Variable O&M; wheeling; emissions charges that are paid directly like SOx or, in southern California reclaimed NOx credits, that sort of thing.

The system cost is inclusive of these production costs on the right, but also includes the capital associated with the transmission or the generation that differs among the scenarios. And it does not include all the capital, so this is not -- we're not readily able to describe these results in terms of impacts on ratepayers, but this is to give you an idea of how total costs associated with generation changes across the scenarios differs from the production portion alone.

And, again, what we're basically seeing is production costs decline from that set of bars on the right-hand side of the chart, as fuel is used less. And on the left-hand side of the chart, system costs go up a little bit as there is more capital associated with energy efficiency and renewables that does not have an operating cost associated with it.

ASSOCIATE MEMBER GEESMAN: When you say that you don't include all of the capital costs under your system costs, what's an example of something that you would exclude?

DR. JASKE: Al the plant put in operation prior to January '07 for example.

ASSOCIATE MEMBER GEESMAN: But going forward there was an effort to include all capital costs?

DR. JASKE: With the exception of those plants in the pipeline that were common across all the cases. So there are certain plants everyone agrees are going to go into operation in let's say mid-1008, too late to affect them. So they would be included in all of the scenarios.

But a plant that was a generic addition that might show up in, let's say, 2011 in case 1, the conventional buildout, later replaced at one of the other scenarios with energy efficiency or renewables, that capital cost would be in case 1 and not in the other cases that caused it to be displaced.

So you can get a absolutely correct differential between the scenarios. Just makes it a little hard to compare to today's total costs.

ASSOCIATE MEMBER GEESMAN: Sure. Thanks.

DR. JASKE: Okay, so that, in fact, completes my sort of overview based on the executive summary of the main report. And so now's a opportunity if there are any questions about the overall design of the project or anything I've covered to date. Do you have any questions?

ASSOCIATE MEMBER GEESMAN: Just to reiterate what you'd said at one of the earlier workshops, these runs largely rely on assumptions that we used in the 2005 IEPR, if I'm not mistaken, in terms of demand, price levels, technology costs and so on?

DR. JASKE: The 2005 IEPR or other things sort of out there in the industry up to sort of late 2006 when we started this specific project.

ASSOCIATE MEMBER GEESMAN: So we haven't captured any of the 2007 work yet?

DR. JASKE: The one portion of 2007 IEPR that is here is the work on cost of generation. So, we delayed the financial dimensions of this project until we could get those results which came sort of pretty late in our schedule.

And so the workshop that you had about two weeks ago maybe, or within the last two weeks on cost of generation, we used a subset of those very numbers.

ASSOCIATE MEMBER GEESMAN: Thank you.

MR. TUTT: Thank you. Can you go back to figure ES-1 in your presentation? I was wondering about case 2; it appears -- the high sustained natural gas price case. And it appears to include a significant amount of energy efficiency, equivalent to the cases 3A and 5A, but no increase in renewables. Is there a reason for that?

DR. JASKE: There is a reason for that. The way we designed that case had to do with -- well, first of all, the premise of the case is twofold. Like case 1, sort of what would utility executives do. But under sustained high gas prices, how would they sort of make their own best decisions.

The analysis that we did seems to show that energy efficiency is far less expensive than renewables. And so they would -- the way we ended up doing this analysis, they would prefer energy efficiency over additional renewables.

I actually have a number of slides about the design of case 2 downstream here, so I could get into that in more detail.

MR. TUTT: Okay. Maybe -- if you turn to figure ES-3.

DR. JASKE: Yes.

MR. TUTT: The difference between case 5A and 5B intrigues me. And, you know, we might cover this later, as well. But in case 5B you're expanding the energy efficiency and renewable aggressiveness to the rest of the west.

And yet the system carbon responsibility actually increases primarily from imports. Do you cover that later, too, or --

DR. JASKE: I will. The simple answer is that there is so much surplus capacity in the rest of the west in case 5B that is cheaper than capacity remaining dispatchable in case 5A in California that it's run preferentially. And because it's so co-laden, it has worse emissions.

So there's more imports and those imports are dirtier than the generation that it displaces.

This turns out to be -- the combination of imports and the nature of the resources in the west, and whether continue to be dispatched on a least-cost basis is an important thing we keep running into in various of these scenarios.

And chapter 10, in fact, proposes some additional work to look into this issue, because it's not something that just pushing more resources into the system is going to solve. May have to more directly impose limitations on coal plants, or go to some sort of a tax on all fuels that would, you know, end up affecting natural gas and coal plants. Or some other means to get the dispatch decision made in a different manner than the way the model says it would be done at least cost with just fuel prices.

MR. TUTT: Okay, one last question. On figure ES-5, it seems like the production cost and system cost different totals for the cases 3A and 3B, for example, or 4A and 4B are very similar. Which seems to imply there's no cost difference when you expand from California to WECC-wide on your efficiency and renewable scenarios. Am I interpreting that right?

DR. JASKE: 3A and 3B?

MR. TUTT: Or 4A and 4B or 5A and 5B, there's much more differences between the cases than 3 and 4, for example, than within California versus WECC versions of it.

DR. JASKE: I think that may be a consequence of how the cases are designed. Whenever there's a B, let's take 3A and 3B, 3B includes 3A.

MR. TUTT: Right. It expands it to the rest of the west.

DR. JASKE: That's correct. And given the information that we have about costs, we are assuming that costs, sort of the first order, cost per unit of those technologies, either efficiency or renewables, is the same in California as it would be for the equivalent thing done in the rest of the west.

MR. TUTT: I see.

DR. JASKE: We don't have good information about differential costs of those technologies deployed within versus without. I have seen some things that talk about differential costs, but we were not able to really bring much of that kind of information into this project.

That could be part of why you're seeing this.

MS. WHITE: Just a moment.

(Pause.)

DR. JASKE: Okay, any questions from the audience about this overview? All right.

So, this section's going to talk some about the methodology and basecase assumptions. I think we've largely covered all these various bullet points, so this is an attempt to build upon prior studies and really sort of dig one level deeper into some of the consequences of high efficiency, high renewable stretch.

We started this project in October '06. There has already been one workshop back on January 29th where we got some feedback from participants. A lot of that feedback had to do with fundamental elements of the project design that we were not able to accommodate unless the schedule was changed. And it was clear that the Committee has directed us to stay on the original schedule. And so we have not, in fact, been able to make the majority of those suggested changes to the project.

And a number of them then show up in chapter 10 of the report as suggested extensions, should the Committee and management at the Commission decide they want to pursue them.

We're using Goal Energy Decisions product called Market Analytics, which involves a number of modules going all the way back to the production cost model PROSYM. Amplifying upon your question before, Commissioner Geesman, we are using significant portions of global assumptions from their fall of 2006 reference case. Certain places we've selectively replaced assumptions they had in their cases with ones that the Commission Staff thought were better.

In turn, their assumptions are a collection of things they have gathered together from utility filings and all sort of various other sources to characterize the portions of the west outside of California.

We have conducted some limited powerful assessments or used other techniques to determine how to add transmission. You probably already got a sense that there's a lot of cases being analyzed here, and so there's a database that takes all these PROSYM results, drops them in, enables them to be compared one to the other much more efficiently.

And then we have a wide range of sensitivity cases doing at least some of the uncertainty assessment that this kind of project needs. And I'll build on each of these as we go through this section.

So, first of all, for production cost modeling, as I said, we're using MultiSYM or PROSYM, depending on how one wants to call that. We're running it in a zonal fashion. There's 29 of those all together, ten of them within California, 19 outside.

We're running this model in a deterministic sense, so we're cranking through typical weeks for each month. And then each typical week's hours are blown up so that essentially the model has 8760 representation for each year. And the model is, of course, pursuing unit commitment and dispatch on a least-cost basis satisfying various sorts of constraints.

These are the three things that we revised directly from what Global had been using. We had a topology for California that was a little bit more detailed than what they normally run when doing westwide studies. So we had them revise it to conform to our practice.

We substituted load forecasts for California that came out of what the Commission adopted in June 2006. And we revised their basecase natural gas fuel price projections.

ASSOCIATE MEMBER GEESMAN: Let me stop you on that last slide, Mike. When you say you substituted forecasts that we adopted in June 2006, that in essence is the 2005 forecast updated for a new starting point?

DR. JASKE: Well, I think a different way to characterize it is its peak aspects are updated for better weather assessment.

ASSOCIATE MEMBER GEESMAN: Okay.

DR. JASKE: And then that was carried forward from just the '07 year that was adopted last June all the way throughout the period. The energy is virtually the same; and those changes in peak were, in effect, extrapolated out to all the years.

ASSOCIATE MEMBER GEESMAN: And when you indicate that you varied from Global's basecase natural gas fuel price projections, what did you substitute in place of Global?

DR. JASKE: I will get into that --

ASSOCIATE MEMBER GEESMAN: Okay.

DR. JASKE: -- in more detail --

ASSOCIATE MEMBER GEESMAN: Thanks.

DR. JASKE: -- in a moment.

So here's the topology. Probably hard to read. The handout is in the report. You can see, just by counting up the bubbles or transareas, as we're going to call them in the report, more emphasis on California. No surprise. Of course, we are also 40 percent of the load in interconnection.

Entities like WECC probably have more granularity out there in other parts of the west. And if you're doing detailed transmission assessments, clearly you'd want that. This seemed to be satisfactory for our purpose.

I think this slide, in fact, covers what we just talked about. I have the summer 2006 vintage forecast was updated. And here is an explanation about how the gas prices were updated.

The blue line is the EIA natural gas price forecast. I believe this is Henry Hub from late December. So it was an early release of their annual assessment.

The green line is Global's fall 2006 fuel price forecast, gas price forecast, out to 2020. Somewhat below, talking with Global we ultimately determined that oil price projection was the principal reason. So when you put EIA's oil price projection in that moves the green line up to the yellow line. And since it was more or less on top of the blue one for purposes of this project, that seemed to be close enough.

And it was important to us that we not just have a set of numbers, but we have a model that generated numbers that were at least in the ballpark of EIA, which in late '06 we thought was a reasonable basis for basecase assumption.

And the need for a model has to do with the issue of generating alternative price projections. So we didn't want just a single line. We needed to have the ability to generate sensitivity and alternative scenarios.

And, of course, there are many assumptions that go into this; and there's a fair amount of documentation in appendix H and its various sub-appendices about this. And a portion of this work is still underway and is, as I mentioned at the beginning of this presentation, will show up as results in July with the intended presentation at the August 13th public workshop.

When we did transmission assessments we actually conducted a fair amount of powerful assessment, but it is mostly associated with the retirement of aging power plants in southern California. That piece of the work is not yet finished and so it's really not represented in the results you're seeing here today. That'll, as I said, be documented hopefully in the next couple weeks so that we can discuss it July 9th.

The transmission additions that are presented here in this study are largely a judgment call using expertise of Navigant's transmission planning folks looking at PROSYM model runs, trying to decide where we have added generation that doesn't seem to be able to get out.

Just deciding to increase the transfer capacity from one transarea to another. And doing preliminary estimates of what those costs might be. This would be very much just a starting point for a real transmission planning effort.

At some point I'll explain this in more detail, but we ultimately had more than 50 separate cases, counting all the sensitivity. So the management of those results and the ability to compare them, one to the other, is very important.

Global had a capability to take their PROSYM results, drop large parts of them into a database in a procedure for devising what we call scorecards that allow them to be compared in certain stylized fashions. And then you can actually post-process that through Excel spreadsheets. So, appendices C and D that were put out last week are example of these scorecards and their sort of post-processing of results.

This gives you an idea how we got up to about 54 cases, so we had the eight basic scenarios other than case 2. Each was evaluated in three variants, three levels of fuel prices. And then case 2, which is only run with one particular fuel price, that makes 25.

All nine scenarios had certain shock sensitivities that just lasted for a single year. We ran those just for year 2020 so as to emphasize the consequences of the alternative resource mixes. I guess it's another 27.

We did do some limited stochastic analysis which is running the model in a Monte Carlo fashion, where it's drawing from probability distributions for five or six variables to give an understanding of really the distribution of certain results. And then all told, then, that's more than the 54 cases I mentioned earlier.

And so that's sort of the end of section B of the agenda. Are there any broad questions about methodology or basecase assumptions that I can answer? Any from out there in the audience?

Okay, I'll move on. So, section 3C of our agenda now is going to be a section that talks about how we actually constructed each of these cases.

And I will go through them pretty much in sequence, because that is the way, in fact, we developed them and ran them. So we were generally in the process of finalizing the characterization of a scenario, getting the initial dataset pulled together that was all the detail for it. Starting the initial runs; debugging those runs. And sort of then repeating that, sort of overlapping manner, for each of the subsequent scenarios, although we were in different stages of development of each of the scenarios throughout the project. We did case 2 last, and I will actually talk about it last in the sequence.

So case 1, as I indicated before, is a continuation of current conditions. It's drawn largely predominately even from Global's fall 2006 reference case. We revised these three things, as I've mentioned before.

And all three of those things were then, in fact, held constant for all the subsequent cases. So in some respects case 1 is sort of the starting point from which all the other cases stem.

Case 1B, its theme is current requirements. So, what are the statutory requirements for renewables through RPS, or whatever various states call that, their local version of that.

What are the levels of energy efficiency that are funded and can be considered committed.

What is going on with rooftop solar photovoltaic. And as the slide indicates, this is being done on a westwide basis.

We had various sources of information to draw upon. Was a study by Itron of energy efficiency potential was released last year, drawn upon data from a couple years before that, that the PUC, the IOUs, and to some degree, the Energy Commission Staff have participated in developing one of these potential studies every so often. So we made good use of that. In fact, we extended that to implicitly address energy efficiency for POUs in California.

We made use of the same buildout of renewable resources that was, I believe, mentioned briefly at the gas assessment workshop several weeks ago. This is an effort that the staff has done several times, attempting to be on top of renewable development motivated by RPS standards, et cetera, in the entirety of the west necessary in order to have a westwide resource plan necessary to understand gas consumption coming out of production cost modeling as an input into gas modeling.

There were some tweaks in this

particular version of the analysis that we used for this project that are not 100 percent identical to what was reported to you earlier in the gas assessment project. But basically it was that same body of work.

MS. JONES: And, Mike, can I ask a question. For each of the scenarios in terms of this buildout for renewables, was there a different mix of renewables?

DR. JASKE: Yes. There are different mixes of renewables across the scenarios. An example is that in case 1, in fact the most conventional of all of the scenarios, renewables is largely wind. The others are not considered to be competitive in the way Global was doing its analysis at that point.

In the case 1B that we're talking about here, there's a broader mix of renewables. And then when we get into the high renewables cases, 4A or 4B, there's different emphasis.

MS. JONES: Okay, thank you.

DR. JASKE: Okay, some more of the details about composition of case 1B. This slide, figure 2-4 from the report, is showing the levels of energy efficiency that were assumed. Shows the three IOUs and a bar for all of the POUs in California.

These numbers are drawn from either the 2006 LTPP filings at the PUC or related documentation that was filed earlier this year in this IEPR. There were some, in effect, extensions of the IOU results to cover POUs that did not provide as much detail as we needed for this project. So there were analogs of efficiency per unit load and things like that that were used to sort of create efficiency program estimates for POUs.

This is the corresponding depiction of what we assumed in case 1B for demand response. And it doesn't grow nearly as rapidly as energy efficiency. Again, this is drawn largely from the IOU filings -- or the two big POU filings to us.

Here's the rooftop solar PV penetration. It's similar to what's in table 22. The years are pushed out all the way to 2020, which that table didn't do.

So in this case 1B we did not assume that California accomplished the level contemplated with the CSI, only getting a fraction of the way there. Arizona and Nevada are also assumed to have rooftop PV programs that would get sizeable penetration, particularly Nevada.

The renewable portfolio standards of course configured it a different way, enumerating different kinds of technologies that are underway in large parts of the west. So that's what the green is showing. I understand that Oregon is pursuing one now, so it might have one before too long.

These are very complicated statutes, as is California's, with, you know, cost type offramps, if the incremental costs become too expensive. So it's really difficult to do a detailed assessment of what is likely to happen under RPS. And the analysis that is embodied in this project or the similar work that's in the gas assessment report is only a beginning to that kind of thing. We don't attempt to say at the level of individual states or individual LSEs pursing state mandates precisely what they would do. So this is sort of a broadbrush treatment.

And so these are the results, I believe the same figure showed up in the gas assessment report appendix last month. This is recording total renewable capacity, and then the wind which is almost always the largest individual component in parentheses below.

So, I'm skipping case 2. I'll come back to that. Case 1B was, in effect, a way of representing current statutory requirements in California and the west. It becomes, in effect, probably of the two we've discussed so far, this is closer to what we would consider a baseline. It's an attempt to reflect the direction that the various states are imposing upon their utilities.

And so for the remaining scenarios we're very much saying, all right, you've gotten so far on energy efficiency, rooftop PV, renewables with these existing obligations. You know, let us now devise scenarios that hypothesize higher levels of energy efficiency, PV or renewables and see what their effects are. And then we'll be able to compare one to the next.

So 3A, in particular, focuses on high energy efficiency in California. We used the Itron study to go up to economic potential for the IOU loads and for the POU loads. In effect, say the degree to which they're lagging behind IOUs now, they will lag behind IOUs pursuing this economic potential.

There also are not good POU energy potential studies. And that, of course, will change over time as AB-2021 continues to roll out and we have more information from POUs, more studies by POUs about energy efficiency.

This is a similar chart to the one we saw a couple moments ago. So these are the higher levels of cumulative energy efficiency in this case. Similar pattern.

MR. TUTT: Mike, can I stop you there. Sorry. It doesn't appear like there are higher levels of energy efficiency in this case for San Diego. I was curious about that.

DR. JASKE: Yes. The question came up at one point earlier. I think it essentially says that the Itron study of potential for San Diego and the degree to which San Diego Gas and Electric is currently pursuing programs are very close to each other. So they're at least within the confines of the Itron study, there's very little potential left in San Diego.

Now, that may mean San Diego's being very aggressive; or the Itron study is weak in how it did this assessment for San Diego. And that's one of the innumerable issues about data and assumptions about what's possible at various levels of cost that we've sort of brought a lot of information together in this project and that's one of the many followups, to really track that down and determine what's the issue there.

You know, is there a mistake that we've made. Is there actually a problem with the Itron study. And if so, is the next one that's being designed now, you know, going to remedy that problem.

MR. ST. MARIE: Mike, I have a question, as well. When we say the word cumulative in this chart, and there was another one like it for 1B, what does the word cumulative mean in this sense?

DR. JASKE: In this instance it means inclusive of --

MR. ST. MARIE: Inclusive of the previous year?

DR. JASKE: Yes. And also inclusive of case 1B levels. So this is the total amount of efficiency that would be achieved in that year by that year's expenditures, prior years' expenditures, across, you know, all authorized programs.

MR. ST. MARIE: Okay. Is there anything

that's going on in the first derivative of these things that we just can't see from looking at the cumulative? That is, do the lines change shape if you were to take the year-to-year differences or something like that?

DR. JASKE: No, not in a significant way. Really, what we did in many of these instances is identify a magnitude that could be accomplished in the out year like 2020, and just ramped up toward it. So that's why everything looks pretty smooth.

MR. ST. MARIE: Okay. So it's essentially flat by a year?

DR. JASKE: I think that's correct.

MR. ST. MARIE: Okay, thank you.

DR. JASKE: Okay, so this chart, figure 2-10 from the report, is, again, using this word cumulative. It's showing something that's very interesting, though. The blue line at the top is, in effect, the -- this is just for California that we're talking about, case 3A. This is the total energy load in California projected out to 2020.

The pink line is what load would be after the energy efficiency is included in case 1B. Then the green line is what total load would be after the further energy efficiency in case 3A. So, essentially in case 3A load is flat. Does not grow. We've managed, through energy efficiency, to keep us largely where we are.

This is a chart that's very similar to one shown earlier for case 1B demand response. Shows a couple additional line segments in bright green and light blue, which have the two POUs a little more called out. This is not very much higher than in the case 1B, and that does reflect the fact that we only made modest increases in DR for this case.

MR. TUTT: Mike, do you have similar information to combining, perhaps, those two charts on the effect in case 3A on peak resources?

DR. JASKE: There is no chart in the report that does that. We can generate one if you're interested. But I don't believe there's a peak-oriented chart.

Because we're thinking in terms of production cost model and particularly the results, you know, are oriented to GHG. We really were oriented to energy-type measures and paid less attention to peak overall.

Okay, so case 3B, high energy efficiency again. Now westwide. So it's going to be the same assumptions as I've just described for California. And so the question is what's energy efficiency in the rest of WECC.

We're going to push it up to the level of economic potential, but our knowledge of what that is is weak.

This is the point which I should probably explain a little bit about CDX, since that was the source of a number of our rest-of-WECC assumptions, not only here for efficiency but for renewables, as I'll get into later.

CDEAC is this Clean and Diversified Energy Advisory Committee that was established by Western Governors Association back in 2005, a large stakeholder effort, in fact a number of separate stakeholder efforts aligned along technology lines.

Bill Keese left the Energy Commission early before his term was over; headed up that CDEAC effort. It provided its overview report and a whole series of task force reports in the late spring and early summer of 2006.

It decided that the evidence was there that 20 percent of energy efficiency could be accomplished; had megawatt targets for various other renewable technologies.

We used the CDEAC task force reports for a considerable amount of rest-of-WECC characterization in this project.

In the case of energy efficiency, itself, there was an LBL report that was prepared for Western Governors Association and reported at CREPC that we also drew upon to some extent.

So here's a chart that shows those energy efficiency effects on WECC loads. So unlike the one in California where load was essentially fla after the energy efficiency had been inserted, there's still some load growth here. You can see the blue segment of this chart is the amount of which overall WECC loads are reduced because of these energy efficiency assumptions.

The overall CDEAC goal is 20 percent. Both the CDEAC report and also this independent LBL report make note of the fact that some portion of that target is, in effect, buried inside the load forecast that utilities make, and that, for example, Global assembles, you know, from various sources in doing its proprietary business with clients.

It's hard to know precisely how much of that energy efficiency is in those utility load forecasts. And so what portion of that 20 percent goal, you know, is already embedded in the load forecast versus, you know, remains to be accomplished through resource planning assumptions like in this case, is clearly an issue that's uncertain.

We, in effect, made a choice based on the information from the CDEAC report through work of Navigant, Craig McDonald, in particular. And used an increment of about 11 percent remaining. So this blue segment of the chart shows about 11 percent reduction in nonCalifornia loads representing a high efficiency case.

Case 4A is high renewables case in California. Wind, central solar, geothermal, biomass and rooftop PV were the technologies that we pursued. We had an increment of about 13,000 megawatts of capacity over and above case 1B by 2020.

We're not doing an RPS compliance analysis here, so we identified an amount of capacity that we thought was feasible. We did not attempt to figure out, you know, how much energy that would generate and compare that to sales, and do sort of an RPS computation. We rather tried to identify the renewables that were feasible, and just shoved the whole lot of it into the system.

That does require some additional transmission capacity to be developed in order for that amount of renewables to be deliverable to load. Obvious example of that kind of transmission that's been talked about for years is the transmission lines up into the Tehachapis in order to allow that wind resource to be developed.

We drew upon a PIER-funded study of intermittency analysis project that is looking at this same subject. We sort of took their distribution and something approximating their level of penetration of the various technologies to define this case.

And there are numerous other studies that were sources of information for the details of the output, how sensitive the output would be to various conditions, costs, et cetera.

This is a summary of the case 4A renewables additions for 2015-2020. As I said earlier, adding up to about 13,200 megawatts of nameplate. And the largest piece here is wind, but PV rooftop is another major component.

Case 4B is again high renewables. This case extending renewables out to all of the west. We identified 16,000 megawatts of capacity beyond case 1B that could be installed by 2020. This again drew upon the CDEAC reports that I mentioned earlier. And there are, again, some transmission capacity development that's necessary in order for this development to be fully integrated into the system and deliverable to load.

This is a portrayal of the particular technologies. And in this instance wind is the overwhelming constituent in the rest of the west. Whereas only the sort of the leading one in the California version.

Case 5A is the combination of high efficiency and high renewables within California. Uses the same magnitude of energy efficiency as in case 3A. Uses the same level of rooftop solar PV as in case 4A. Uses the same level of supply side renewables as in case 4A.

We didn't really use any new information, we just sort of pushed all of these elements together. So, again, unlike an RPS assessment where the energy efficiency would be deducted from load and there would be a lower percentage if there was a RPS type target that was to be achieved. We did not do that kind of computation.

If it was physically feasible in case 4A for a certain level of renewables, we preserved that level of renewables. In this case it was feasible to have a certain level of energy efficiency affecting load in case 3A we preserved that same level. Pushed everything together.

And the very same process was followed in case 5B. High efficiency, high renewables in all of the west. The same levels of efficiency, the same levels of supply side renewables and PV. Had to change transmission a little bit in this particular case compared to the earlier ones, but that was the principal way in which modifications were made.

Now, case 2. Case 2 is sustained high fuel prices. Our original idea was that this would be an attempt to reflect how utility managements would make decisions in the face of high fuel prices. Sort of curious to know what the distinction would be between what they would do, operating from a reduced cost, least cost in sort of a cost orientation compared to the policy orientation perhaps best reflected in case 1B.

We used the costs out of the cost of generation study as I discussed earlier. So our first necessity was to develop a high sustained price. The blue line on this chart is the basecase gas assumption; hovers around $6 a MMBtu as I showed earlier.

The red line at the top is the sustained gas price projection that Global Energy developed. They did it by taking their original model -- remember, I emphasized the need for a modeling capability -- increased oil prices, modified the gas production cost assumptions, both of those in directions that would cause high levels of gas prices.

And this was their attempt to identify the highest level of gas prices that could be sustained before major fuel switching would take place. And these values hover around the $10 a MMBtu level.

So that was the input assumption, so to speak, that was different in this case, driving the resource mix. There's a comparable change in coal price projections. It was decided that coal price couldn't remain constant, that there would be some reflection of those higher gas prices in at least somewhat higher coal prices.

So there's two different coal producing regions here. Powder River Basin are the two lines on the bottom. The blue at the very bottom is the basecase. And yellow is the higher. So a very modest increase in coal price.

And the two lines at the top are sort of the other producing regions in the west in the Rockies. The red being the basecase and the grey being the higher coal price. So they go up maybe in the 5 percent range.

ASSOCIATE MEMBER GEESMAN: Any effort to calculate a carbon regulation cost in association with your coal price projections?

DR. JASKE: No. We have not done anything to try to translate the GHG perspective into a higher coal or maybe more generally, a higher fuel price, you know, like a Btu tax or something, that would perhaps be legal under interstate commerce clause prohibitions against interference in interstate trade.

And that may very well be a necessary

next step for this project to deal with. Some of these things we're finding out about coal and how coal continues to be dispatched. We'll see in more detail in some of the results later the availability of surplus coal, you know, in effect getting dispatched to serve California load.

You know, there's no -- we just basically don't think that when you put new -- well, renewables in particular, into the system they're essentially going to displace coal. They're going to displace gas because already a differential between gas and coal.

Whenever we do something that creates more surplus coal it's going to continue to be reallocated to somebody else.

ASSOCIATE MEMBER GEESMAN: But these are essentially then unregulated coal prices.

DR. JASKE: That's correct. This is merely how would the coal industry, in effect, take advantage of higher gas prices.

Okay, so those two sets of costs, basecase hovering around $6 MMBtu and the high sustained gas price hovering around $10 a MMBtu, are the two left-hand columns -- excuse me, the two right-hand columns. The one called fixed cost is just that. It's dollars per megawatt hour absent variable cost of which the major component is fuel.

So the way to read this chart is here's the fixed costs for the various technologies; $6 a MMBtu. Here's the increment of al the variable costs, predominately fuel. If you go from $6 to $10, what does that do to change the relative economics of these various technologies.

Because coal price responds very little coal stays, you know, as by far the cheapest. Natural gas jumps really up there from $62 a megawatt hour to $90 a megawatt hour. Of course, the renewable technologies don't change. Another assumption.

And so really what we concluded was that there wouldn't be a shift from gas to coal. Coal's already cheap. To the extent -- and there wouldn't be a shift from coal to renewables, because coal is still cheaper than renewables. And so all those places who, by law or custom, are still allowing utilities to build coal plants would continue to do that.

And in the end we sort of concluded that energy efficiency was really the one really obvious choice that these higher fuel prices would make more obvious, more prominent in utility decisionmaking thought processes.

And so we essentially decided to add energy efficiency first. Essentially use the levels that we had from the previous cases simply because that was available to us. And then made some modest switches in a couple limited instances.

So, I think this analysis turned out to be less than we originally anticipated for it. It didn't lead to sort of huge insights about how technology mix would change. And maybe an area that we need to follow up more in the future.

Okay, so that's the conclusion of this segment of the agenda talking about how we devised the cases. Are there questions about this piece of the work?

Okay, looks like we have some from the audience this time. I guess what would be best is just to come up to the microphone, say your name and ask a question about it. And I'll attempt to respond.

MS. JONES: I'm Jacqueline Jones from Southern California Edison. And I just wanted to clarify some of the information in the tables as you were going through.

There is a table, well, it says revised version of table 2-2, where it's rooftop solar PV penetration. In the handout it's page 13.

DR. JASKE: Okay.

MS. JONES: Are we talking about megawatts here?

DR. JASKE: Oh, yes. This is megawatts of nameplate capacity.

MS. JONES: Okay. And also with respect to the projections for cumulative impacts of energy efficiency, so figure 2-4 and figure 2-9 is that gigawatt hours --

DR. JASKE: Yes.

MS. JONES: -- megawatt hours?

DR. JASKE: These are gigawatt hours.

MS. JONES: Gigawatt. All right. Thank you.

DR. JASKE: Um-hum.

MR. TUTT: Mike, can I follow up on that a little bit. In the case of the solar PV penetration, is there some penetration of photovoltaics that's already included in the load forecasts? Is this incremental of that?

DR. JASKE: I think the answer is yes, there is. And the way it has been conducted it's, in effect, buried in there without being identified as to the level that it is.

So, if you sort of think about an econometric analysis using historic sales data, you know; it was an unexplained factor causing the actual -- or the projection to be higher than the actual. You'd, in effect, calibrated away without really understanding precisely what level it was.

I've heard numbers like 150 megawatts, but I don't fully understand whether there's a formal analysis that lets us track things that closely. And differentiate between that which is buried in the load forecast and what's incremental. This is incremental from the perspective of this study.

MR. TUTT: Okay, I'd have to check the numbers, but I think we have close to 180 megawatts, if not more, of rooftop PV installed today. And installing about 80 megawatts a year. This would be maybe perhaps incremental about on that? Or is it a reflection of that in some other way?

DR. JASKE: This would, I think, be a

different view than 80 megawatts per year. So this is -- I've not heard that particular number before. This is -- these projections that we're seeing right here are one scenario to come out of a PIER-funded study by Navigant of rooftop PV that devise several different scenarios of penetration based on certain costing program design subsidy levels.

And this is a lower subsidy level than some of the alternative scenarios in that study. Would use the higher ones in case 4A and 5A.

MR. TUTT: Can I ask then about case 4A. I look at that table, there's a negative 232 for CSP in 2015.

DR. JASKE: Yeah. I believe that is a reflection of the timing differences of certain projects that were in case 1B versus case 4A. So that's sort of an artifact of a particular project showing up in a different year, depending on which source we were using. Whether it was a source we used from a separate study or generated in this project. So I think that's just an artifact of timing.

MR. TUTT: Okay. And then on the PV rooftop numbers there. It would appear there's fairly strong growth in PV rooftop installations up to 2015, and then it would look like it slacks off a little bit. Is that a proper interpretation, or something else?

DR. JASKE: Yes, that's correct. We have major growth in 2015, '16, something like that. And then sort of the slope of the line, you know, definitely drops off and grows more slowly after that.

MR. TUTT: And there's a rationale for that in the report?

DR. JASKE: Yes. Perhaps in the appendix that deals with solar technologies.

Okay, over here.

MS. TURNBULL: Jane Turnbull from the League of Women Voters. I just have two questions about clarification. One has to do with figure 2-4. It shows between 2015 and 2016 a switch, putting PG&E having greater energy efficiency as of 2016 than SCE; but prior to that time PG&E lags behind SCE.

Is that an anomaly or is that real?

DR. JASKE: As far as I know that's just an element of what they have put forward for their long-term energy efficiency program goals. I don't know how to explain it.

MS. TURNBULL: Okay. Also in figure 2-11, I'm assuming that you're not including the proposed new standard for demand response, or a proposed new standard for demand response.

DR. JASKE: Yes, at the time we were devising these analyses, we were not aware of any of those proposals.

MS. TURNBULL: Because I think that would be very interesting to see.

DR. JASKE: Well, it would affect the resources a little bit, but probably wouldn't really affect the overall energy results. And therefore, the GHG emissions.

And so as I was explaining before, and it might, of course, affect costs a little bit between ER programs versus cost of peakers. But because it's largely not an energy consequence, it really wouldn't affect the GHG emissions.

MS. SMUTNY-JONES: Robin Smutny-Jones with Cal-ISO. Mike, I just wanted to clarify something. Pages 18 and 19, case 4A versus 4B. It looks like -- I thought that the WECC cases included California, so I was confused to see the numbers, for example, with PV rooftop 3000 and then 88 and 423.

Is the 4B then exclusive of California?

DR. JASKE: Yes.

MS. SMUTNY-JONES: Is that how all of them are working? I guess I got --

DR. JASKE: Yes, right.

MS. SMUTNY-JONES: Okay, --

DR. JASKE: 3B and 4B, when these inputs are recorded like this, they're the increment from going from 3A to 3B, or the increment of going from 4A to 4B.

MS. SMUTNY-JONES: Okay, so the Bs are exclusive of California.

DR. JASKE: Right.

MS. SMUTNY-JONES: Okay, thank you.

MR. McCARTNEY: Wade McCartney, CPUC, Division of Strategic Planning.

Mike, on the total number of cases evaluated on page 10 of the hard copy, I guess you did shocks for each of the nine cases that you presented here in detail?

DR. JASKE: Yes, we did actually three different shocks. I will get to that more later. But we did a high and low hydro; and then an extremely high gas price for each of the nine.

MR. McCARTNEY: Okay. And on the fuel prices you only did eight, there was one scenario that was left out. Which one was that?

DR. JASKE: We left out case 2, which was, itself, designed, you know, around this idea of $10 a MMBtu. That was already decided at that level. It didn't seem worth putting in fuel price assumptions that were actually lower than that as alternatives.

MR. McCARTNEY: And on the stochastic analysis, you only did two scenarios. Which ones were those? And can you provide some more detail on that?

DR. JASKE: We will. But they were case 1 and case 4B.

MR. McCARTNEY: Okay, thanks.

MR. WANLESS: Eric Wanless with NRDC. I know you said you didn't include some of the costs of carbon, but I just want to clarify, is that including the current adder in the CPUC for the IOUs? Is that not included?

DR. JASKE: Correct. No adder.

MR. WANLESS: And then my other clarification question is in the cases with high energy efficiency. I think I read in the report that anything above and beyond the current CPUC goals was assumed to be the full incremental cost, is that correct?

DR. JASKE: The way I understand it is in case 3A we were, in effect, assuming the costs up to economic potential. So various measures that were cost effective, you know, had their own individual costs that were on an overall basis were added together, along with their magnitudes.

And then what probably was recorded in the appendices is sort of the average cost per kilowatt hour or per megawatt hour. But that's, in effect, a weighted average of the various measure costs with a little increment on top of that for overhead.

MR. SEZGEN: This is Osman Sezgen from PG&E. First a clarification. The energy efficiency levels which came up a minute ago shown in figure 2.4 in case 1B was for a low gas price case for PG&E.

And subsequently in March we updated our plan, amended our plan. And then in that plan all our scenarios have energy efficiency levels as shown in close to 3A actually. So just a clarification.

DR. JASKE: I'm not personally aware of that change. I think I had heard some anticipated discussion of PG&E making a change, but I didn't realize that you had submitted it. So we have not included those revised numbers in this study.

MR. SEZGEN: This is just for clarification. I know it was late in the game for you to update those.

The other question I have is to do with in your preliminary findings you mentioned that increased penetration of preferred resources reduces greenhouse gas emissions significantly even on dispatchable resources to assure reliability are taken into account.

Now, my question is in the resource cost tables the cost of wind for the different gas price levels seems to be the same. And I was just curious about how you modeled load following and reliability associated issues to do with wind.

DR. JASKE: That table only shows the direct costs associated with the individual technologies. It doesn't show any consequences of, for example, discounting the capacity to follow resource adequacy protocols; or it doesn't account for other kinds of integration costs.

So in the methodology section, chapter 5 of the report, there's some discussion of how we tried to impose, you know, sort of a simplified version of resource adequacy calculated capacity on a derated basis. So in the case of wind it was a very large discount. And then backfilled, as necessary, with combustion turbines.

So, that's the consequences of that process show up in the cost analyses. But they're not, in effect, spun out to be cost per unit of the individual technology in the initial instance. So it doesn't all get traced back to wind, for example.

MR. SEZGEN: Thank you.

MS. JONES: Mike, what capacity factor did you assume for wind?

DR. JASKE: It varies, essentially by using a version of the PUC's net qualifying capacity protocol. So wherever we had actual wind production data which was several years for California, one year for each area outside of California, we calculated the seasonal dependable capacity number.

Generally in California it would be in the 20 to 25 percent range, something like that.

MS. JONES: Thank you.

MR. TUTT: I've one final question, as well. Modeled in case 1B the renewable portfolio standards across the west. Did you attempt to include specifics of those like the set-aside in Arizona, I believe, that calls for a certain amount of distributed solar as part of that RPS?

Also, a similar thing in California, the Governor's biomass executive order is not really a part of the RPS, but there's, you know, specific targets set out there for biomass.

DR. JASKE: I don't know precisely how we're treating, you know, the separate biomass activity in California. I'm simply not sufficiently aware of that renewable penetration to know how we're dealing with that.

The PV in Arizona comes out of a study that Navigant did for the State of Arizona. So, again, they had several different scenarios that characterize that penetration.

Whether it's part of their RPS or an independent state initiative I'm not, myself, sure. But we were taking advantage of that work that Arizona had done through Navigant.

MS. GREIF: Claudia Greif. I'm here for

the ISO. Mike, I just have one question. On page 13 you just said that the Arizona PVs were calculated by -- came from a Navigant study. Is it true? I mean, are these numbers really zero here? Or should they be zero or why are they zero?

DR. JASKE: I suppose that that's, again, a reflection of existing program perhaps embodied in an APS or a Tucson Electric or Salt River load forecast versus the incremental effect of a new program.

MS. GREIF: Thank you. And just for curiosity, these numbers, you said they're megawatts, right?

DR. JASKE: Yes.

MS. GREIF: So what roughly like 108 megawatts, do you know about roughly how many rooftop panels, or how many customers?

DR. JASKE: Oh, 10 kilowatt panels are pretty common, so --

MS. GREIF: Okay, thank you.

DR. JASKE: -- that's probably a good rule of thumb.

MS. GREIF: Thank you.

DR. JASKE: Okay, I'll move on to

section D, having to do with technologies. So I think in some other question I alluded to the fact that what we really would have liked, of course, are supply curves of the various technologies that give a clear indication of amounts and costs.

And, of course, we'd like them to be zonal or transareas or states or, you know, something like that.

There are bits and pieces of that floating around, but nothing that is systematic and all done in the same way. And so we were forced to sort of bring together a whole lot of information from various previous studies. And, you know, in effect, try to make what use of it we could.

So, there's very substantial uncertainty in a lot of the costs technology characteristics elements of this project, that as chapter 10 said, could well be done in approved basis in some subsequent phase or another project.

And we did acquire some results from PIER-funded research projects before they were completed, and have now been completed, I believe. Again, using pieces that hopefully the main report, itself, will have documented.

MS. JONES: Mike, just to clarify then, you didn't use supply curves but you used current assumptions. And you didn't assume a declining cost curve over time or technological development? You froze technology costs and the technologies, themselves?

DR. JASKE: Yes, that is correct. So, with the one exception that rooftop solar we did assume that it would drop from about $10,000 a kilowatt to $5000. Sort of out there about ten years ahead. it seems like there's no way the CSI could ever be accomplished without, you know, some major cost reduction of that sort.

All the other assumptions were, in effect, the most recent numbers held constant through time. And the most recent numbers, again, coming from the staff cost generation study that was put out a few weeks ago, that you held a workshop on earlier. And, in turn, a number of those assumptions for renewables coming from a PIER-funded project that Navigant Consulting did for the Energy Commission.

So this slide I have on the screen now is the major sources of the various kinds of the three elements of the preferred strategies, energy efficiency, rooftop solar PV and supply side renewables.

Certain things from out of state were largely just taken on faith from the CDEAC studies. So there's different levels even of uncertainty among these sources.

So just to give you an idea of the cost variation across the renewable generating technologies, here's an instant cost chart. I believe this may also have been in the cost of generation study, or certainly its data was. This comes from a PIER-funded study by Navigant. Shows where things are as of today if you were trying to go out and do one of these kinds of projects.

This figure 4-2 shows the potential that we made use of mostly in case 3A. So this is something already in effect that's gone from potential to an assumption in the report. And the only thing remaining would have been technical potential that wasn't identified as cost effective, which we did not use. And this just shows a little bit about what customer sectors that could come from.

These very colorful bars are the costs associated with those energy efficiency potential.

And there's slight variations across the major IOUs that funded the Itron study; modest variations across some of the customer sectors. And they all sort of cluster, in the end, on the right-hand side in an average kind of way, around $2000 a kilowatt.

And if you go back to this instant cost, $2000 is right about at the same level as wind, and lower than all the others.

Now this chart, figure 4-5 from the report, shows an important element of the data that we had to acquire about energy efficiency. And that's the shape of the load impact.

So the work that we paid Navigant Consulting to do, not only looked into the energy efficiency potential study by Itron, but attempted to merge it with the best data that we could find on measure and end-use load shapes.

So at the bottom of this chart are a depiction across all the various measures put together of their hourly profile across a typical seven-day week in April. Those, then, you know, act as load modifiers to the original loads, which are shown in blue at the top.

And then you have the resulting modified loads in yellow. So, there's some preferential impact on peak, tends to reduce the peaks more than the offpeak. And so the overall, if you were to do a statistical analysis, the resulting yellow or gold line would be just a little bit less peaky than was the original.

Very same phenomenon shows up in this figure 4-6, which is for a typical July week. Again, the energy efficiency shapes are peaky; they correlate strongly with the underlying peakiness of the load shape. And so the resulting load shape is a little less peaky.

Here's an understanding of the level of efficiency -- excuse me, of demand response capacity available by utility. And, again, we ended up using the information that we had available to us, which was, you know, largely what the utilities had proposed in their various filings. And there isn't a god source of DR potential because DR ended up not being emphasized in this project.

As I also indicated earlier, DR, by just clipping peaks for a few hours a year, really is not going to have a significant impact on carbon emissions anyway.

So, rooftop solar. We were able to benefit from both PIER-funded Navigant study, and also this Arizona-funded Navigant study. There are two slides that take tables out of the appendices, appendix G in particular, that look at penetration of California of PV, separating out residential and commercial.

So this is the low-penetration scenario; this table from appendix G-4 is the high penetration. So if I go back and forth between these two out in 2016 to 844 versus over 4000. So major change in the level of penetration.

And as is indicated on the caption of the slide here, there's differences in these between how the systems are priced, you know, how the industry is presumed to go about doing their business, and the levels of incentive, all of those factored together into these different penetration estimates.

Okay, so that was a quick tour through the limited information we had about technologies. There's a little bit more in the main report, itself. But, as I said at the outset of this little segment, we did not have a full-blown sort of supply curve that really was a characterization of technology costs. And the overall capacity, you know, on a locational basis, we pieced together various elements from different studies.

And in response to your question, Ms. Jones, we did largely assume static technology costs through time. So this is an area in which the sort of foundational work available to this project was weaker than what we might have anticipated when we started.

So, are there questions that you have? Questions out in the audience?

MR. WANLESS: Eric Wanless with NRDC. I just wanted to make a quick note with the cost of generation work that's been done at the CEC. I believe in the workshop last week, in terms of looking at forward prices for technologies, I think in addition -- excuse me, I think that if I remember correctly IGCC costs were assumed to be more forward looking in the cost of generation model that the CEC put together.

I just wanted to note that. I think that's the case, but I don't know if you can verify that or not.

I think I remember hearing that at the workshop.

DR. JASKE: Perhaps. I was not able to attend that workshop so I didn't hear that directly.

MR. WANLESS: Okay, thanks.

DR. JASKE: Anything else? Okay.

So in this segment of the agenda and the two that follow we're going to be going through the results.

This particular piece focuses on what's reported in chapter 6 of the report. It's the sort of deterministic analysis; and it uses the baseline fuel prices; it uses the basic characteristics of the scenarios.

It has taken all those; it has cranked them through production cost models; some supplemental analysis to identify, you know, transmission additions and their costs, et cetera.

And then all of these results are brought together in the so-called scorecard, as is documented in appendix, I think, 3 and 4 of the appendices volumes. And then there's some supplemental spreadsheets that have been also posted that provide all those results electronically.

We'll run through just a pot pourri of

the results using the figures and tables from the main report, looking at these different sort of viewpoints: electricity production, how GHG emissions change, fuel use, costs and criteria pollutant.

So this is a chart, figure 6-1, that I believe is identical to figure ES-2 in the executive summary. We're looking at the composition of generation to meet California load in 2010. Stacked bars indicating the different resource mix, and the various bars showing all the cases.

Of course, in 2010 there's very little difference across these scenarios. There's hardly been any time for any change to happen.

Similarly, here's where things are in 2010 for the rest of WECC using the same style. And what is added in this rest-of-WECC figure is a little indicator of the level of exports and from a perspective of rest-of-WECC and California that's all there is in the whole western interconnection. So, these exports from WECC are identically California imports.

And then there's a little red line showing where the top of the bar would have been just to serve WECC's loads, itself.

Now things get more interesting in 2020. This is the one that's actually in the executive summary. So there's more variation. You know, as I explained this chart earlier, so you start seeing the peak energy efficiency, and then the various renewables in their colors like wind being this light blue with a little shingle pattern growing larger.

All of that has the consequence of natural gas, being the green diagonal bar, shrinking as you have more and more of the preferred resources. The corresponding chart for rest of WECC.

And, again, the gas, which is the smaller percentage part of the rest-of-WECC bar also using the same color convention, it's the green slashed one that is the one perhaps more variable.

Okay, there's a couple charts that use this style, figure 6-5 from the main report. We're looking at California instate carbon production. So here we're looking at across time from 2009 to 2020, and then for the various scenarios.

So, as you might expect, at the top is the conventional scenario that involves, well, case 1 which involves the most of conventional generating resources. And then as you go through the various cases, the lines are lower and lower till you get down to case 5B, which is the lowest. Again, intuitively, as one would expect, with both high efficiency and high renewables.

This is a similar chart, but it's focusing on the total California carbon responsibility. So in addition to instate that we were just looking at, this adds remote and adds imports.

As I explained in one of the earlier charts today, the remote is nearly constant across all these scenarios, so that tends to move things up and decrease the spread between the various lines.

And then the imports is the most variable, so there's some moving around of the individual lines. But generally the same result is that the high combinations of efficiency and renewables; 5A and 5B, are the two at the bottom in case 1, the conventional, of course, would be expected to be at the top. And it is.

Here's rest-of-WECC carbon production through time. Much narrower spread. The vertical axis doesn't go all the way down to zero, but it goes pretty close to zero. So, percentagewise there's less variation than within California. And if you think about it, that's where most of the coal is. The coal is hardly affected in all these cases, so there's a huge sort of fixed component that isn't changing across the cases.

There's a series of figures in chapter 6, starting with this 16-8 that focuses on the elements of California carbon responsibility, and show how they change over time.

The blue segment at the bottom being instate. The reddish one being what we call remote; those plants located outside of California but are owned by California utilities or under long-term contract.

And then the tan segment being the imports.

At least the blue rising slightly over time in this conventional resource plan case 1. The other two being more constant. But the overall then rising slightly over time.

Now, in case 1B, which is current requirements, so we've added energy efficiency, renewables and a little bit of rooftop PV. Sort of along the lines of current requirements.

Clearly the total now is lower. It's lower because the blue doesn't grow quite as much, and the tan line diminishes significantly over time in contrast to the earlier.

So, we have the same three-colored elements of carbon responsibility. And there's a blue line at the top to remind us where case 1 was. And we'll be able to use that to sort of keep track of where these various scenarios are relative to case 1.

Case 3A, the high efficiency, within California. You can see that it goes a little bit further to diminish total carbon responsibility. And in part what it's doing is reducing the growth of the blue.

Figure 6-13, which is case 4A, high renewables in California, has an even greater reduction relative to case 1. And you see a very pronounced decline in the import element of carbon responsibility.

And then case 5A, which is both high

efficiency and high renewables, is even more so. So blue is now declining very slightly; imports decline a great deal, probably down to 10 percent of their initial level. So, we're now around 60 percent of the original 2009 level by 2020.

Another time trend style chart showing, in this case, gas consumption for power generation. Again, the 3 case is different from the various cases; different lines; the conventional resource plan case 1 at the top, and case 5B, of course, at the bottom.

Here's the same style of chart for total WECC; so this is inclusive of California in this instance, figure 6-17. Again, a very similar picture as the previous one just for California.

A little bit of comparison of California versus rest-of-WECC for UEG gas consumption in just year 2020. You can see that California has gas consumption nearly as large as all of the rest of WECC, which indicates the different resource mix between California and the rest of the interconnection.

And then those relationships change significantly from one case to the other. Generally instate use of natural gas for power generation declining as the scenarios unfold. And whether or not there's a change in the import level as part of the explanation for why the bars are sometimes close to each other, as they are in case 3B, or sometimes far apart, as they are in case 3A.

Coal consumption. Again, things about as one might expect, although finally in case 5B both high efficiency and high renewables in all of the west, there's coal consumption that sort of stabilizes at about the current level, whereas it's been rising through time in all these other cases.

Of course, there's hardly any coal consumption in California, so it hardly shows on this chart.

Okay, a little bit about the cost consequences of the cases. So, this is looking at the data from table 6-18 of the report. Comparing all nine cases. Looking at total WECC system cost on a -- so actually the units of this should say 2006 dollars per megawatt hour. That's an omission from this slide.

So, total WECC system cost sort of average basis, case 1 column $32.94 per megawatt hour. You read down the table, California higher than that; just above $40. Rest of WECC then is even below the total WECC system at 29.12.

And as these numbers show, there's a general trend as the cases involve more efficiency or more renewables for there to be an increase in this levelized cost. That happens at the WECC level; it happens at the California level. Also happens at the rest-of-WECC level, although a lesser degree.

This --

MR. ST. MARIE: Mike, could we go back to the one for a second? Okay. When I compare the California system costs between case 1 and case 5B, it goes from 40 to 51. In essence is that saying that costs would be 25 percent higher in California under case 5B? Is that what that means?

DR. JASKE: This is where the definition of what costs are included becomes very crucial. I think a better way to think about this is that there's a $10 per megawatt hour increase. And that the ability to translate that into a percentage increase in rates is what the weakness of omitting the existing and the named addition capital.

And keeping track of all that rate-based capital and its depreciation, et cetera, means that it's very difficult to identify a rate increase out of --

MR. ST. MARIE: Okay.

DR. JASKE: -- these analyses. But I think it's fair to say that there's $11 per megawatt hour increase between case 1 and case 5B for California.

MR. TUTT: Mike, just to clarify further, these costs don't include the production costs, is that correct?

DR. JASKE: No, these do include production cost.

MR. TUTT: They do include the production cost.

DR. JASKE: Right. So, production costs are generally going -- in fact, I think there will be slides that show that. These are totals; these are both production costs and a portion of capital that we were able to analyze.

MR. TUTT: Then one last question. For the rooftop PV and energy efficiency costs, the total cost of those technologies are included?

DR. JASKE: Yes.
MR. TUTT: -- the customer-supplied portion of those costs would not be included in any rate calculation or comparison, is that correct?
DR. JASKE: Yes, that's correct. They commonly are not. What we're using as sort of a societal perspective here, where we're trying to capture all costs.
ASSOCIATE MEMBER GEESMAN: As I understood you earlier, at the very beginning of the morning, these are marginal resources, new resources brought into the system going forward, and they exclude a number of projects that are not yet online, but which is assumed will come online in the next several years.
DR. JASKE: They're a cost assessment of resources that are at the margin.
ASSOCIATE MEMBER GEESMAN: I had a question of a more general nature in terms of your chart showing net carbon increases, or I believe a decrease in -- that one.
DR. JASKE: That's gas; carbon?
ASSOCIATE MEMBER GEESMAN: Yeah. What was your conclusion or inferred assumption

regarding the impact of the California and Washington State carbon standards?

It seems to me, and I'm not saying that this is the right table that I was focused on, but it seems to me that to the extent that you have coal use increasing around the west, you're assuming some new coal projects, and some new coal projects that potentially through resource switching, are not built or financed with either California or Washington State loads in mind. Is that a correct conclusion on my part?

DR. JASKE: This study was not able to incorporate either of those two state carbon standards. So, we are not directly addressing those requirements. But in general, I think what we're doing is we're trying to address how -- and that's one of the issues we've already touched upon and the report tries to explain -- needs even more assessment than we have, is what are the consequences of the existing and the remaining coal plants that will come online that are considered committed, already, you know, in the pipeline, of having those plants. And their costs relative to other costs. And how they'll be dispatched on a cost basis.

So to the extent that there is a carbon standard that the state has that doesn't affect the operation of those plants is just a shuffling around of who's going to, in effect, get the attribution from a WECC-wide perspective.

And we are not taking any of those things into account. And I think it's one of those issues of the difference between a study sort of organized around a physical depiction of the system versus a, you know, an accounting or a contractual perspective. That we have to figure out how to look at both of those perspectives. And so far we're only looking at the physical perspective.

ASSOCIATE MEMBER GEESMAN: The chart I was looking at was your figure 6-20.

DR. JASKE: 6-20, okay, thank you.

ASSOCIATE MEMBER GEESMAN: In there it looks to me like in all of your cases, except 5B, you've got an increase in coal consumption. And I'm wondering to what extent that increase is driven by new plants.

DR. JASKE: It is driven by new plant, but please note that the vertical axis has got a, you know, a long ways above the zero point. So these lines are a lot flatter if we looked at them, you know, from zero-point axis.

There's about -- this question came up in the January workshop. I think they're somewhere in the range of 8000 or 10,000 megawatts of coal capacity that's in the pipeline that is the main reason that this consumption goes up over time.

And so if we actually went back to, you know, a recorded year like 2006, it'd be yet lower. So there's some coming online, already online this year and in '08, as well.

ASSOCIATE MEMBER GEESMAN: Thank you.

PRESIDING MEMBER PFANNENSTIEL: Mike, can I look at table 6-18, the levelized system cost by case. I remember you had commented that these costs don't include -- nowhere in your analysis do you include a carbon adder or carbon tax.

DR. JASKE: That's correct.

PRESIDING MEMBER PFANNENSTIEL: But sort of qualitatively were there a carbon tax, I'm trying to figure out whether it would show up very much. Because, as you pointed out, coal would be most hit by it; and coal is, in none of these cases, on the margin.

Would it make much of a difference among the cases? Clearly, everything would go up, but would it vary among the cases very much?

DR. JASKE: It could vary across the cases if you got a level high enough that the coal wasn't always the least-cost choice. So if it was elevated to the point where it --

PRESIDING MEMBER PFANNENSTIEL: So if it became such that coal was marginal, then it would make a difference in the cases?

DR. JASKE: That's correct.

PRESIDING MEMBER PFANNENSTIEL: Thank you.

DR. JASKE: Okay, so I believe this is just a graphical depiction of the very same table we've just been looking at. This is a very interesting chart. Let me try to explain how it works.

So, for the moment what we have is across time, so the horizontal axis is 2009-2020. The vertical axis is annual average cost per megawatt hour. Focus for the moment on the middle two lines, the dark blue one and the pink one.

The pink one -- those two lines are

associated with case 1, the conventional buildout resource plan. The pink one is the production cost associated with that case 1. The blue line is the total cost associated with that case.

And the pink one obviously dominates. So there's only a small margin above production costs for, again, this limited amount of the total capital costs associated with the production costs. That's all the production costs, but only a piece of the capital costs; it varies from case to case.

Then the outer two lines are case 5A. And, again, we're only looking at California numbers. The turquoise line, which is the case 5A production costs, is down relative to the pink production costs in case 1, but the total system cost, the yellow line in case 5A, is higher than its corresponding dark blue line in case 1.

So, the very tight correspondence of total cost to system cost -- or to production costs in case 1 has become a much less tight relationship as these two depart.

And this is sort of, if you think about it, this is what you expect. Production costs in high efficiency, high renewables case go down.

We're using less fuel. Fuel's the major part of production costs. We're investing either in generating capacity or in energy efficiency that doesn't have any variable costs, or at least the efficiency part doesn't.

And so the question is how much would it cause things to go up. What this chart is telling us is that there is a decrease in production costs through time. There's an increase in system costs. And so the spread between them becomes very pronounced in comparison to conventional relationship.

I think at one point I recall in the 2005 IEPR, Mr. Geesman, you said something like, you know, fuel is 85 percent of all that counts in terms of combined cycle plant. So it's the fuel price that's the dominant assumption. Well, that wouldn't be the case in this sort of future that we're talking about, things that don't have fuel costs.

ASSOCIATE MEMBER GEESMAN: And that's with respect to new resources because you've not made any effort to replicate the continued operation of our existing fleet of generators in this graph, as I understand it.

DR. JASKE: We have their costs in the production side. We don't have their costs on the capital side. So, the blue line for case 1 and the yellow line for case 5A are lower than if we had included all of those capital costs.

The pink line and the turquoise line wouldn't change because those are inclusive of everything.

MR. TUTT: And, Mike, the reduction in production costs depends significantly on what fuel prices you assume. And the increase in the capital cost depends on what capital prices or costs you'd assume for those technologies.

And as I understand it, other than PV you've assumed that they stay as they are today for most of these technologies?

DR. JASKE: Yes, that's correct. Both of those statements are correct.

And part of what we'll look at later this morning concerning chapter 8 is the sensitivities we did relative to fuel costs. We were not able to do sensitivities with respect to production cost -- or I mean capital costs, technology cost assumptions.

Okay, just sort of winding up this

little segment of things. This figure 6-24 just gives a very quick review of NOx and SO2. We calculated these using sort of conventional emission factors for the various kinds of technologies.

We have not really studied these results in any depth. And I don't know that they actually are very meaningful in a broad California setting. They are meaningful at an airshed level perhaps.

And the same thing for rest of WECC. Minor variations across the various scenarios.

Okay, so that sort of concludes this tour of, you know, how the individual cases, individual scenarios turned out. We've compared them sort of to each other, the sort of stacked bar chart or line graph formats.

Are there questions about those results before I move on to another way we looked at the results?

MR. WANLESS: Eric Wanless with NRDC again. Sorry to be asking so many questions. i want to just --

DR. JASKE: That's why it's a workshop; go ahead.

MR. WANLESS: Yeah, there's a lot of

great work that's gone into this. It's going to be extremely useful, especially in the AB-32 implementation context.

Going back to table 6-18, I just have a quick note, and I think this will maybe come up a little later. My, I guess, biggest comment in terms of the overall report is the presentation of total costs in addition to the per megawatt hour costs. I know it's in the report, but I also notice that it's not presented in the executive summary, I don't think.

So if you look at say case 3A versus 1B on a total system cost, I believe that 3A comes out as being about a $700 million less in terms of absolute costs.

And I think, especially in the context of using this as a broader tool for California and looking at societal costs in terms of what we're going to be doing with our greenhouse gas emissions and that sort of thing, I think it's really important that we present, in addition to the per megawatt hour levelized costs, the total system cost in terms of absolute dollars upfront, and someplace where it's easy to find for decisionmakers. Thanks.

DR. JASKE: Thank you. Other questions about sort of chapter 6 version of results?

So this piece of my presentation comes out of chapter 7 report. The cases were designed in such a way that they can be compared one to the other. And we've done that in sort of broad terms in chapter 6 that we've just gone through.

What we're doing now is looking at how particular pairs of cases compared to one another and what inferences we can make about what that means.

So this is a version of that same chart from the executive summary; sort of shows how the cases were constructed relative to each other. So, we start with case 1. We then went to case 1B. Essentially we added efficiency, renewables, solar PV. We backed out assumed generic additions to the extent that made sense, while still following a resource adequacy sort of protocol.

Case 1B then led to going over to the right to case 3A high efficiency version, where we added more energy efficiency and again backed out more generic combined cycles and combustion turbines to the extent that they were not needed.

Case 1B was then also the starting point for case 4A. So it went up with the same level of efficiency, and of course, more renewables, again backing out generics to the extent possible.

And then case 5A is, of course, the combination of those two. And then down here at the bottom, case 2, which was sort of the utility executive pursuit of lower cost in the face of sustained high gas prices. Didn't turn out to be very insightful.

So, if you look at those various cases in pairs, the very first row of this table, which you don't have in your report but it's in the handouts, by comparing case 3A, high efficiency in California, with case 1B you can get a very clear understanding of the effects of energy efficiency.

And correspondingly, as indicated here, case 1B is the starting point for 4A and case 5A, being able to understand things for California.

You can have different choices of what to use as your reference case when you're looking at cases 3B, 4B and 5B. The way this is organized is the row that talks about case 3B and using case 3A as the reference point, what you would get by that comparison is an assessment of what are the consequences of the incremental energy efficiency in the rest of WECC on either rest of WECC or California. And similarly for these others.

And chapter 7 goes through each of these six pair-wise assessments. And I'm going to devote some time to several of those so you get a flavor for the results. I'm not going to cover all of what chapter 7 encompasses.

So, we're going to look at each of these things in terms of generation changes, cost implications of those changes and then GHG emissions.

Okay, so this is table 7-1 from the main report. And it's got rows that are sets of things for year 2015 and 2020. I wish in retrospect I'd just used 2020 here for this presentation so you could see it better.

And the columns are two pairs of columns; one pair for California generation, one pair for rest of WECC. So those are disjoined. The rest of WECC does not include California.

And the pair of columns associated with California has assumed increases. So in this instance in year 2015 we assumed a certain level of energy efficiency increase; and the model predicts a certain level of decrease in the next column over.

So this is the same table. I'm now just highlighting the particular cell so we assumed the 6596 gigawatt hours of energy efficiency. We got, within California, 44,000 approximately. Reduction in gas-fired generation; a little bit of change in pump storage.

We also got a change in rest-of-WECC generation. So of the roughly 6600 gigawatt hours of increased energy efficiency, two-thirds of that shows up as California combined cycle generation reductions, and one-third as rest of WECC combined cycle.

So what's on the margin in both rest of WECC and California is combined cycle gas, or maybe a little bit of combustion turbine, too, as we increase energy efficiency. Coal hardly changes.

This table 7-2 from the report again is looking at these two cases, case 3A with case 1B is the point of reference, looking at the difference. So, focusing on 2020, there's a number of elements of cost here I'm going to run through.

So, in case 1B the 2020 system costs

were 16.4 billion. They go down to 15.7 billion. So that's a reduction of 700 million a year. Production costs actually went down more than 700 million, it went down about 800 million in that year.

Efficiency programs costs were actually higher. Generation capital, as it reflects some limited amount of generation that we could back out, and so capital that was embodied in case 1B was no longer needed in case 3A. And then there were a little bit of transmission changes that had to be done. So all of those elements, production cost, efficiency, program costs, generation and transmission, you know, sort themselves out to be about a $700 million decrease.

MS. JONES: Mike, I had a question that's not directly related to these sets of charts, but it goes back to the protocol that you used for resource adequacy.

In the way you applied that, do you end up with a 15 to 17 percent reserve margin? Or in some years where you have high renewable and efficiency you keep some of that generation on so you have a higher reserve margin?

DR. JASKE: This is an important

question. We originally set out thinking that we needed to have something like a resource adequacy protocol. And we just decided to adapt something like what California had.

So we have a 15 to 17 percent planning reserve margin. We had a discounting or a derating of various technologies, capital capacity, excuse me, following net qualifying capacity rules. We imposed that on the various transareas.

Turned out that as a general rule we couldn't back out as much generic conditions as the capacity value of the resources that we inserted. So, in fact, by the time we got to case 5A and 5B there were generally no generic assumptions left at all. So the planning margins actually went up in the preferred cases compared to the conventional case.

This consequence has sort of two roots. It has to do with the additions that we think are committed, that are coming online, even though they're somewhat incompatible with the preferred resource additions that policymakers would like. And what do you do about existing plant. Do you retire them early; do you do something to sort of get these things off the books.

It has both operational issues, you know, carbon generation issues, but it has -- they're just sort of in the way and aren't needed aspects that lead to, in effect, more resources in total than anyone's realistic planning margin we think is necessary.

Now, --

MS. JONES: So do those reserve margins then contribute to the total system cost? And how much?

DR. JASKE: They would lead to probably higher total system costs than if we'd had more optimized portfolios. And several ways that that could get closer toward an optimization.

We could have slowed down -- we could have changed the level of efficiency and renewables; or we could have slowed it down so we got to the same levels later, extend the analysis out to 2025, perhaps. We could have dealt with existing plants through some sort of retirement assumption. A variety of ways we could get things to line up better that to some degree they're called out in chapter 10 of the report.

But they do lead to higher margins than

anyone would think is necessary, and higher capital costs, for sure. You're carrying plant around that essentially isn't fully utilized.

This particular chart also -- and this is identified in the chapter 7 discussion -- focuses on the cost streams of these two particular years, 2015 or 2020. So these are, in effect, an accounting level look at costs.

The previous chart we spent considerable amount of time looking at was levelized. So there are particular consequences in individual years that, you know, you don't want to over-focus on, because levelized is probably a better understanding of how things really work out through time. But you would, in fact, have to be paying these kinds of costs, or receiving these benefits in these individual years.

This is again a table straight out of the report focusing on the carbon consequences. Again in case 3A, high efficiency, we're comparing it to case 1B. We have California carbon go down about 5 percent. That's the instate part. Remote hardly changes at all. Imports goes down. So there's a total reduction of carbon California responsibility in this particular scenario.

This is the same kind of chart as table 7-1. This one now examining case 4A. So, high renewables in California. So we have a listing out of the annual generation by wind, geothermal, biomass, central solar and rooftop PV. Those are the energy consequences of that 13,000-some megawatts of capacity that I talked about earlier.

So I'm going to use this same table and I'm going to shade it like I was doing before; trace through these consequences.

So, here's our assumed increases. Here's the consequences for California generation. There's actually about 40,000 gigawatt hours worth of renewables. There's about 20,000 reduction in California. And another 20,000 or so over there in the rest of WECC.

So, again, a major proportion of the consequences of this within California renewable strategy is a change in imports for California.

This is the cost side of things. This chart is constructed the same way as the one we looked at a few minutes ago for energy efficiency. Here in 2015 and 2020 there are system cost increases in both years. They're a consequence of production cost going down, but capital costs going up. And the net being on the positive side.

Again, as chapter 7 of the report identifies, a number of these technologies are showing up very rapidly toward the tail end of the analysis period. They have useful lives beyond the year they're installed. So levelization is the traditional way that you're able to look at those and decide whether that's a good idea or not. These particular charts are organized around a snapshot of the sort of cash flow in that year.

MS. JONES: Mike, that raises the question of end effects, and are you going to cover that later or --

DR. JASKE: Well, yeah. We use that word right now. I will touch on it later. End effects is the issue of how to conduct the analysis in a way that makes an apples-to-apples comparison instead of apples-to-orange comparison.

So, let's say, for example, in the year 2020 here the bottom half of this chart, we have introduced a certain amount of renewable capacity. It has costs that show up as capital costs here in the row called generation capital, $2.1 billion worth.

Those plant will last let's say 20

years, so any kind of amortization schedule would only cause a certain portion of those capital costs to be incurred here just in this one year. And so this is not a complete depiction of the cost effectiveness of that kind of technology.

What we -- levelization is a way to spread those costs more clearly and only account for the portion that's within the study period. We could have extended the study period out longer, 2025 or 2030.

So there are a variety of ways in which the conjunction of the time pattern of when resources are brought into the system and their costs and how to account for lives that go beyond the year of analysis that need to be taken into account in either just understanding what it is that's being reported, or potentially in some modification of the analysis in the next stage.

MS. JONES: So, Mike, then it increases total system costs in the late years for those investments. What does it do to production costs? How you treated the variable portions.

DR. JASKE: The costs are, I think, done accurately. So to the extent, you know, that last increment of capacity is added in that year, and it displaces generation equivalent to its capacity and its capacity factor, then I think the production costs are an accurate portrayal. So this $2 billion reduction is accurate.

Table 7-6 again looked at the carbon emissions, comparing case 4A to case 1B. Compared to the previous chart of this style looked at a minute ago, these are larger reductions. In fact, even the remote line for California goes down a little bit, not very much in percentage terms.

So, overall, we're down something like 18 million tons. Total WECC is also down somewhat in this portrayal down at the bottom of the chart.

So, again, style of chart here where we're going to now look at case 5A, which is the combination of high efficiency and renewables. We have even more complicated chart. We have energy efficiency as the first assumption that's highlighted in yellow. And now we add the same level of renewables as we had in case 4A. So this case 5A has both those components.

We're getting these kinds of decreases. Again, about half in California, about half outside of California.

And again, this is the same kind of cost perspective or carbon perspective as we looked at for the individual efficiency or renewables.

I want to focus on just one of the sets of tables having to do with out of state. A piece of the strategy because I think that's useful to understand how it works in that way.

So, in this instance what we're doing is looking at case 3B. Case 3B is energy efficiency in rest of WECC. But remember, it also has energy efficiency in California. But the incremental change is just energy efficiency in rest of WECC.

It's a pretty large number, a bigger number than we have looked at in any of these other cells, 82,000 gigawatt hours. It primarily shows up as reductions in generation in rest of WECC. Again, predominately gas, but also some coal.

It also shows up as changes in generation in rest of WECC that is exported from rest of WECC or correspondingly imported into California. And then a two-zone depiction, whatever's exported from WECC is an import to California.

So part of how this decrease in native load in rest of WECC affects things is to have more exports from rest of WECC into California. And this last slide highlights where that shows up. Shows up as a reduction in gas-fired generation in California.

So, as I pointed out at some point earlier this morning, when there is surplus, cheap capacity in rest of WECC, it displaces more expensive capacity in California.

And that's why in those various charts the import levels jump up and down a lot from one case to the other.

Table 7-11, again is the same format, but now we're comparing case 3B to case 3A. And so the changes are all costs from the perspective of rest of WECC, and would, of course, be paid for by rest-of-WECC ratepayers.

This table shows the carbon consequences of the incremental effects of that case. And here you see some interesting consequences. In the top tier of lines, looking at things from the California perspective, California CO2 production goes down. We saw that because those gas-fired resources went down.

California remote CO2 goes down a little bit, but not much. The California import CO2 goes up. And it goes up because overall imports are higher; and there's a mixture of gas and coal resources that are used to compute this level of import CO_2.

Okay, I'm going to skip these slides because they are in the same format as everything that you've seen. And pause here and ask if there are questions about this segment of the presentation that had to do with comparing the cases, one against the other, and trying to infer the consequences for energy efficiency or renewables.

Questions from the audience?

MS. SMUTNY-JONES: Thanks. Robin Smutny-Jones with Cal-ISO. I'm not even sure exactly how to ask this question but I'm going to try.

Mike, I'm trying to figure out how this relates, if at all, to the analyses and efforts underway with respect to aging power plant retirement studies, once-through cooling, other policies that have an impact on how we're going to be able to maneuver our resource portfolio going forward.

Has there been any effort, or will there be an effort to coordinate these types of analyses?

DR. JASKE: The last part first, because that's easier. Yes, there has been an effort to coordinate some analyses of aging power plant retirement between the Energy Commission and the ISO.

We have actually got some analysis that is sort of at the pre-preliminary stage. We have provided it to the ISO and asked for its review. Because it has not gone through that review, we have not documented these results.

We are hoping that we can get that review; and assuming it's positive we can tidy it up, do some further analysis of some of these within-California scenarios. And then ship out those results in the next couple weeks, so that it can be talked about at the July 9th workshop. That's our aspiration; that's dependent upon the ISO getting us some feedback fairly quickly.

What that would do is -- well, what has not been done is in -- excuse me, what is not reflected in the results presented in the report or my presentation this morning is the particular attempt to identify the consequences of the policy that the Energy Commission adopted in the 2005 IEPR.

We have, in effect, made use of a lifetime -- a retirement strategy that simply says a power plant operates until it reaches year 55 of its life, and then it's retired. And that happens whenever, you know, that works for various power plants.

What we are trying to do in our retirement analysis is two things. First of all, pay attention to the year 2012 as the Commission identified in the 2005 IEPR. Identify the consequences of a large group of plants retiring by that year. Ascertain how it is those power plants that retire have to be replaced by comparable capacity. And then tie that to the scenarios so that, in a conventional scenario, we would presumably do that retirement and replacement with similarly conventional capacity.

But in the high renewables scenario, try to replace that capacity with renewables to the extent possible.

Of course, since renewables are not located inside, you know, the load pockets or close to load centers like most of the aging power plants are, there may have to be some dispatchable capacity that is located in closer to load centers. Or the transmission system may need to be reconfigured somewhat. Or both.

And that issue of the transmission system reconfiguration is precisely how it is that ISO's review of this preliminary work is so critical. And why we have not yet been able to publish it. But hopefully can do so shortly.

So, our intent is to rerun certain of these scenarios for the transareas affected by these aging plants, and re-report the results.

MS. JONES: Mike, there was just one oddity on this series of charts with the pumped hydro, or the pumped storage. I know it's a small number, but if this was an energy analysis how did we end up with pumped storage increasing? Because isn't it usually dispatched as a peaking resource?

DR. JASKE: I'm going to let one of our friends from Global answer that question.

MR. LAUCKHART: Pumped storage in modeling is pretty complicated. We spend a lot of time working with our algorithms to make sure we're doing that properly.

Pumped storage, of course, when you use

it you get capacity. And then, of course, you want to pump stuff up, you lose energy when you use it. So depending on the shapes of the loads and when the model decides it thinks it should use it or not, you'll end up with different energy net consumption of the pumped storage plant.

So it's really a product of the fact that the energy efficiency numbers change the load shapes; and the model found different ways to use that pumped storage.

MS. JONES: Okay. And then related to looking at aging plant retirement and additional dispatchability needed for renewables, is pumped storage one of the ways you can get that? And can you look at that through this study?

MR. LAUCKHART: Well, I think you're talking about two possible different things. One is, you know, if I do some kind of a spreadsheet analysis and I thought I might have a problem from a capacity standpoint, you know, can the pumped storage help. And you can address the question that way.

What we do in this modeling is we test different possibilities and run the model; and it tells us how the pumped storage operates and how it impacts the various alternatives you're considering.

MS. JONES: Okay, thanks.

MR. TUTT: Could you just provide your name for the record, please?

MR. LAUCKHART: Yeah, I'm Rich Lauckhart with Global Energy.

DR. KENNEDY: Mike, I'd just like to draw attention just to one comparison that you didn't actually make. You've been doing a really good job of sort of trying to sift through a lot of very complicated information.

And in looking at the numbers going to the high efficiency in the rest of WECC, you're pointing out that compared to the high efficiency in California case, you end up with California greenhouse gas emissions going up.

But if you actually use a starting point back at case 1B, the California greenhouse gas emissions go down in I guess it's, remembering my numbering right, 3B versus 1B.

So, you know, I think the way you're presenting these is very useful, but I think that's one particular point that's useful to keep in mind when we're looking at the rest of WECC doing high efficiency. If we start with everybody going to high efficiency, California's emissions are going down.

DR. JASKE: Thank you for pointing that out. There's lots of different vantage points one can use. And sort of ran out of time to do it all.

DR. KENNEDY: I appreciate what you've been able to do in terms of doing a very clear summary of a lot of very dense amount of information.

MR. WANLESS: Eric Wanless, NRDC. I have a quick clarification question, and just another request.

In these tables, especially the cost-comparison tables, am I correct in understanding that this is a comparison, a snapshot from that year in time? So it's a cost in year 2020 or cost in year 2015?

DR. JASKE: Yes, that's correct.

MR. WANLESS: Do you have -- I think I did see this in there, but do you have total cost for the entire period, cumulative cost savings, or increases, comparing --

DR. JASKE: We are reporting in the so-called scorecards, or maybe it's in this down to the level of the spreadsheets that are posted on the website, there are the ability to sum up costs across time, which is partly what the levelizing thing is doing.

In fact, since the fuel price in the basecase doesn't change very much, the levelization numbers are almost like adding them all up and dividing by 12 or something.

So the data is available for you to do that.

MR. WANLESS: I'd just like to reiterate, I think that's important to present somewhere upfront and easy to get to.

My other question is I know that including carbon costs in terms of the modeling and what that does to the resource mix and so forth is not really something that's feasible at this point in time, but my question is is it possible, I guess, in the report to do a little bit of easy analysis taking it a step further from the reported greenhouse gas emissions to the potential added costs for given levels of a carbon price.

And just kind of give people a sense of, okay, it's not something that's informing what the model's putting out in terms of resource mix, but if there was a cost of carbon, this is what it might do in terms of impacting the total costs for these different scenarios.

DR. JASKE: That's probably feasible with enough lead time. And I guess if I sort of understand things correctly, a small enough carbon adder wouldn't necessarily change the dispatch decision. And so it would, in effect, be a reasonable estimate of sort of a tax.

Of course, it would be a tax that wouldn't accomplish anything except raise some money.

MS. JONES: What is you were to use the PUC value for carbon, which is up at about $10 now. Started at 8 and then escalated. Is that in that low range you're talking about, or wouldn't that be significant?

DR. JASKE: I'm not sure, actually. Other questions?

MR. KNOX: Bill Knox, Energy Commission Staff. Mike, in the tables of cost does the system costs row include all of the other costs below it?

DR. JASKE: Yes, yes.

MR. KNOX: So it includes the transmission and the rooftop PV and --

DR. JASKE: Right, so the four lines below, you know, are the pieces that --

MR. KNOX: But then are there other pieces, as well? It seems like there's some additional that must come in to make the total system cost.

DR. JASKE: I think there -- at least all the principal ones are there.

MR. SEZGEN: Osman Sezgen, PG&E. I was wondering if the power prices associated with these runs are available in the output. It would be very useful for us when we are constructing our scenarios for the extreme cases, so that we -- since we are not doing the whole west, looking at our service areas, it would be useful for us to have the power prices in a correlated fashion to the --

DR. JASKE: Well, what isn't present in the results is anything more than production costs. So, you know, production costs are, of course, famous for not being a good predictor of market clearing prices. But production costs are there.

MR. SEZGEN: I see, thank you.

PRESIDING MEMBER PFANNENSTIEL: Mike, if there are no more questions on that section, this might be a good time to break for lunch. Does this work for you?

DR. JASKE: That works great for me. My voice might recover.

PRESIDING MEMBER PFANNENSTIEL: I thought you might want to take a break.

(Laughter.)

PRESIDING MEMBER PFANNENSTIEL: Why don't we come back at 1:30. We'll reconvene promptly at 1:30.

(Whereupon, at 12:09 p.m., the Committee workshop was adjourned, to reconvene at 1:30 p.m., this same day.)

--o0o--

AFTERNOON SESSION

1:35 p.m.

PRESIDING MEMBER PFANNENSTIEL: We're back for the afternoon session. Mike.

DR. JASKE: For the record, Mike Jaske with the Energy Commission Staff.

So, here in this section of the agenda I'll be presenting some results of the sensitivity assessment which was recorded in chapter 8 of the main report.

There are three kinds of sensitivities that we conducted. We knew, of course, that various of our input assumptions could be predicted with great accuracy. Lower and higher fuel prices in particular being one of those. And because of the financial nature of what we were trying to do with some of these results, we decided from the beginning that was a sensitivity that we wanted to investigate.

Also we identified several things that we called shocks, that rather than being a whole alternative trajectory through time, that these would be specific things that might last for a year. And you would return to sort of the baseline assumptions.

And then finally a stochastic assessment trying to better understand, instead of just particular alternatives, a distribution of results based on a probablistic sampling from among a set of input data for which we do have that kind of data.

These, of course, all collectively cover all the uncertainties that exist. And we've discussed many of the ones that we have not yet been able to address. For example, technology change, or even technology cost and performance uncertainties.

This chart, taken from table 5-5, simply is a summary of which particular thematic scenario had which sensitivity. So mostly the nine thematic scenarios had a high and a low fuel price and also the shock sensitivity.

Only a few of them had the stochastic assessment because that analysis is so time consuming. That takes a whole week of running the model to do one stochastic assessment.

And then a few of these also were augmented by side analyses that we'll talk some about now; and others are still in process.

Okay, so what are the alternative fuel

prices that we used for the fuel price sensitivities. The blue line, again, was developed by the Global Energy folks by, in effect, re-running their model with higher world oil prices, or falls on top of the EIA line, as I had in a chart before.

The red and the yellow then are alternatives with -- around that basecase natural gas price projection that represent particular probabilities of occurrence.

In the bottom case, 25 percent, meaning it's 75 percent likely that gas prices will be higher than that. And then a 75 percent P-75 case at the top, meaning there's only 25 percent probability it'll be higher than that.

MS. JONES: Mike, can I ask a question there?

DR. JASKE: Yes.

MS. JONES: How many years of historic data did you use to base that probability on?

DR. JASKE: This is a good long period, I believe, maybe like ten years. There is documentation of this method in one of the appendices. It's called a stochastic assessment. And from the perspective of the global gas people, these are not alternatives in the sense of scenarios; they are a reflection of the historic variation that we've experienced, projected into the future around the basecase.

MS. JONES: Great, thank you.

DR. JASKE: So they're a device useful for this kind of sensitivity testing. They're less useful in terms of understanding what gas prices could be at the low or the high end.

These are the similar results for the coal prices. And there are, again, differences between Rocky Mountain and Powder River Basin sources of coal.

In conducting, you know, this sensitivity we're re-running all the models, or excuse me, the production cost model for all the cases. And there's lots of variables that you might expect to change. Some of them are susceptible to large changes like production costs, because it's dominated by fuel. Whereas other things would be expected to have small or negligible change like resource mix.

From a capacity mix perspective we're not changing these resource plans to adjust to these high and low fuel prices. We're merely saying, given a particular resource plan, how might it be operated slightly differently, and what would the cost implications be of the higher and lower prices.

So there's a series of figures that resemble this one, 8-2, from the report that are showing both of the pieces of cost that we talked about in several earlier segments of my presentation. System cost, production cost. Production cost is pretty cleanly fuel plus the other components that are variable. System cost is that plus the portion of capital that we were able to cost out, both on the generation additions or the transmission side.

And around the base values, which are the dark blue line with triangles for system, and the red -- well, what is that -- kind of a fuschia, someone is helping me out here --

(Laughter.)

DR. JASKE: -- with little cross-hatchings, which are the base fuel price. Then there are the others which are with high and low. And so there's a spread around the basecase in both the system and production. And because everything's sort of on top of each other in this instance in case 1, it's sort of hard to see with all these lines what's really going on.

As we go through these alternative scenarios, then the group of system costs and the group of production costs are going to tend to separate and you can more clearly see what variation exists.

So here's case 1B, current requirements were embodying the degree of energy efficiency and renewables and a little bit of rooftop solar PV that are currently required by statute. And there's a little bit more separation between system and production in this case. Already having lower natural gas used as power generation and more reliance on preferred resources.

This figure 8-4 looking at the high efficiency case in California, and now the six lines are beginning to separate more into the two groups, the system costs beginning to move away from the production costs.

In this case, 4A with high renewables in California only, now we have a very clear differentiation. There's the production cost side of things has come down. There's a spread around it that you can easily see that's on the order of maybe $4 a megawatt hour on the upside, and about $6 or $7 a megawatt hour on the downside. And then the system costs are increasing over time, and they have about that same spread.

And if we go back to the fuel prices, themselves, there is a lower -- the lower fuel price is further away from the baseline than the high is above. So that's why the production costs, and also the system costs, have that same distribution. There's a little bit more downside with those particular set of prices than with, you know, some other set of prices.

And then finally in case 5A, we see the most separation, the greatest degree of utilization of nonfuel resources and corresponding higher capital costs as that's tradeoff.

Okay, so the exogenous shocks that we were looking at is another way of understanding sensitivity of the results to things that are variable. We ended up with three of these shocks. They're designed to last one year. So, as you're moving along sort of the baseline trajectory, suddenly something happens which is a departure from that baseline trajectory. You experience it, and then you return to that baseline.

So obviously low and high hydro are illustrations of that. We have a lot of data about hydro variation. And we also identified a extremely high natural gas price sort of excursion from normal that is very much a hurricane-Katrina type event where production capacity is taken away for awhile, but it's replaced.

These are the high and low hydro generation assumptions compared to normal. So there's about 56,000 gigawatt hour increase, and about a -- what is it, 33,000 gigawatt hour decrease. So it's skewed a little bit toward the WECC; it's not completely symmetric.

And here is -- and in the modeling I don't think we've shown these results in any detail released so far, but the conditions of wet and dry are, in fact, the actual month-to-month generation patterns of those particular periods. So, you actually get a chronological effect through time that's also different than just these magnitudes I've reported on an annual basis.

MS. JONES: And how many years did you go back to identify wet and dry conditions?

DR. JASKE: These are the extremes of the period we have available, which I think for a whole westwide it's back to '82 or something like that.

MS. JONES: Okay.

DR. JASKE: Is that right?

MR. SPEAKER: I'd say '28, (inaudible) covers the period (inaudible).

DR. JASKE: Oh, I stand corrected. Back all the way to 1928.

We assumed, sort of just by fiat, $20 a MMBtu gas price. We imposed a monthly traditional pattern of those gas prices on it; so that's what the model was exposed to month by month for that sensitivity.

Okay, these stack bar charts, again directly from chapter 8 of the report, show the variation across the -- so in this particular instance, the figure 8-11, we're talking about case 1. So on the far left we have the basecase; everything is the same as has been reported before.

The first bar to its right is dry hydro. So, hydro, which is the sort of orangish-coral color, our bar is a little bit smaller. Can't see the full variation that I reported before because this is only the California part. And we only have a piece of that. And so gas bar is a little bit bigger to make up for that.

The next bar over, high hydro, is, of course, the complement to that. The gas goes down because the hydro goes up. The gas is the swing fuel predominately. There are some changes in imports in this sensitivity case that are a little more pronounced than the dry hydro one.

In the gas one, to the far left is kind of hard to see how much differences there are, but they don't appear to be as large as to the two hydro ones.

In case 1B the charts are designed to be in the same format, but flipping back and forth between the two of them, this is case 1, case 1B has more renewables, particularly wind and energy efficiency down at the bottom of the bar. So you see these two new colors that are showing up.

And the gas being sort of swing fuel between cases, as well as within a case for these sensitivities, is a little bit smaller. It's the main thing being displaced.

Here's case 5, jumping all the way to high efficiency and high renewables. And here, of course, there's more of renewables of various kinds, different colored segments to the bars, and the natural gas has declined.

And there's a little note at the top of the second bar, the dry hydro bar, which says in this particular instance California actually becomes a small net exporter in this particular case of dry hydro.

This chart, figure 8-20 from the report, is attempting to identify how system costs have changed. Obviously in the $20 gas shock there's a very large increase compared to the others in both case 1B, which are the four bars to the left-hand side; and in case 5, the four bars to the right-hand side.

There is a slight diminishment of the height of that bar reflecting the different resource mix between the two cases.

This is the same style of chart, 8-21. Here we're looking at just production costs. And as you would expect, production cost variation shows up more because there's substantially less fuel being used in the case 5A than the case 1B. And so the instance of $20 a MMBtu gas for that one year of 2020, the system is much less sensitive to it.

The last piece of sensitivity analysis we did was a stochastic assessment again of just year 2020. That particular year because it's furthest out, the most difference among the cases because of the resource mix.

This list of variables, natural gas fuel prices, daily loads, unit outages, weekly hydro generation and wind and solar production profiles were characterized not in their sort of average or deterministic manner in which they're used throughout all the cases.

Here there's probability distributions of different kinds of these variables that are set up. And then there's a Monte Carlo analysis that draws from those probable distributions. And the model is run, you know, repetitively over and over again. Results saved, so that you can then look at how the results differ with different combinations of these things.

And each of these five variables is a dependent of the others with the exception that in the tails of the load distribution where load is extremely high in California, the wind is forced to be low, because that is the actual experience in the peak conditions that we have observed in the recorded data. That the atmospheric conditions that lead to hot peak temperatures, I mean really peak like one or two days a year, are stagnant wind. And therefore, wind generation is very low in those specific circumstances.

ASSOCIATE MEMBER GEESMAN: So, you, in essence, froze the geographic and temporal distribution of the wind production based on whatever your historical observation's been, carried that through to 2020?

DR. JASKE: Let me clarify. We have modeled the wind by zone. There are a mapping of the four wind zones into the different transarea. So each of the transarea does this independently. And each of them has their own independent future penetrations of wind.

So there is not exactly a static mix move forward. But some, at least minor, variation.

ASSOCIATE MEMBER GEESMAN: What are your four zones?

DR. JASKE: Solano, Tehachapi, San Gorgonio and what am I leaving out --

MS. SPEAKER: Altamont.

DR. JASKE: -- Altamont, of course. So

those are the four wind zones for which we have extensive hourly production data.

ASSOCIATE MEMBER GEESMAN: You made no effort then to pick up out-of-state wind generation as a part of the mix?

DR. JASKE: No, no, we do have out-of-state wind. It follows the production profile connected to the one year of production data that we have from National Renewable Energy Laboratory. So there's selected wind projects around the west for which there are hourly production data. Those are used to characterize all the wind in those transareas.

And so whatever their temporal profiles are, the transareas always assumed to have that profile, even if it scales up from 100 megawatts to 1000 megawatts.

ASSOCIATE MEMBER GEESMAN: Thank you.

DR. JASKE: So what we were attempting to discern from this analysis. We were really looking for two things. Where were we going to run into any kind of reliability issues as we made a big shift in resource mix from the conventional to as-available resources that can't be controlled.

And then we just wanted a better understanding of the distribution of some of these outcomes than could be done just by assuming particular sensitivities and cranking those out.

As I mentioned, we only ran two cases because the run time on the model is so long. We can obviously do more, but we sort of ran out of time and energy for this report.

These are the results, focusing on the sort of reliability aspect of things, which you can see reported in terms of margins down at the bottom of these columns.

So this is for case one, a conventional case. This is for all the west. Have this much load. We have resources capable of generating considerably more than that -- excuse me, these are megawatts, so it's capacity. And we have a margin far above the sort of general notions of 15, 18 percent that people commonly talk about as being appropriate for a planning reserve margin.

That meant that the model wasn't going to come up with any useful results in terms of outages. And so we decided, just as sort of a brute force technique, to reduce thermal generation until we got to a point where we could actually observe outages, something in the vicinity of one being 10-year loss of load probability. We had to remove nearly 20,000 megawatts of resources to get to that level.

So the case 1 resource mix built out all the way to 2020 using the kind of techniques we were using, you know, in effect resulted in an over-built resource plan that, you know, had no probability at all of having any kind of outages. And we had to sort of manually doctor it to get it down into the right range.

ASSOCIATE MEMBER GEESMAN: How did you determine which resources to take out?

DR. JASKE: I think we were just taking out thermal on a sort of cross the various transarea bases, and we weren't trying to do it selectively in any particular area.

Part of this result is the fact that the west, overall, is over built from an energy perspective. And when you add -- let me back up to try to explain this.

Part of the reason is the different peaking times of year of the different transareas. And when you impose a 15 to 17 percent planning margin on them, any of them that were below that be forced up to that level. If they were above that, we didn't take anything out to get them down to that level. You try to put them all together on a coincident basis.

For example, the winter peaking ones have huge amounts of excess capacity in the summertime. And so we end up with these high coincident planning margins that have in part to do with requiring each transarea to be independently resource adequate.

And that's probably overly conservative assumption in terms of how the whole of what the west ought to be planned.

This table from chapter 8, table 8-6, looks at these results from the cost perspective. So, again, we're just doing the two cases. On the left-hand side we're doing the deterministic values that were reported elsewhere. And then the three columns to the right are the stochastic results at the 10th and 90th percentile.

So you would think that the expected values and the basecase values would line up relatively closely because the whole idea is that the data inputs into the model ought to show that. And they're off 1 or 2 percent perhaps.

So then the 90th and the 10th percentile results give you some idea about how costs can vary around that expected value, or around that basecase.

The two charts that follow now, figure 22 for case 1, and figure 23 for the next one, depict all the 100 cases that were run. And gives you not only the 90th and 10th percentile, but the actual shape of the distribution.

So this is the shape of the case 1, the conventional resource mix shows that you can go all the way down to maybe about $38 billion, all the way up to about $56 billion, centered somewhere around 44, as I recall.

And then here's the same format for case 4B. Lots of renewables. The expected value has shifted a little bit to the right, as the table showed. What the interesting thing here is that the shape of the curve has altered a little bit.

This curve is a little bit closer around the expected value than this one. So I'll just go back and forth between the two. Here's case 1, case 4B. And part of what's going on also is that the upper end, the maximum value hardly changes between -- you can see where the right-hand-most point in that curve touches the horizontal axis somewhere around 56. That doesn't change.

But what's going on is that the low end goes up considerably. So it's around 38 in case 1, it goes up to somewhere around 44 maybe.

And that's actually, one facet of that is what you would expect. If you have low fuel prices, or other things in conjunction with low fuel prices, take you down. If you have less fuel oriented resources, then you'll have less opportunity to benefit from that.

Of course, you want to be sure you're not paying too much for that opportunity, either in expected value of the very high side. And it doesn't look at though, with these results, the very high side penalty hurts you. But the average does seem to be a little bit working against you.

So this is sort of summarizing what I've just said. 4B is a little less sensitive to fuel prices. It skews over to the right. But it misses out on some of those low side opportunities if and when fuel prices are ever that low.

Okay, so that is the conclusion of the sensitivity portion of this presentation. Are there questions about sensitivity assessment?

Questions from the audience or the phone?

Okay. Oh, here's one.

MR. SEZGEN: Osman Sezgen from PG&E. Just a clarification. When you were doing the fuel cost sensitivity, the trajectories you show for gas prices, the high and low. Are they intended to be sustained high gas prices, or are they snapshots every year -- a trajectory of those annual snapshots?

DR. JASKE: Yes, let me go all the way back here so we can be -- the appendix, it's one of the appendix H's of the report, describes this as stochastic gas prices.

So I think the way the Global Energy gas team would characterize these as in any particular year you wanted to cover 50 percent of probability distribution, it would be this much on the upside going up to the red, and this much on the downside going to the yellow.

So, they are, as I said before, they are not truly alternative scenarios of high and low gas price. They are the expectation of a variation in gas prices in any one year, given where you are in sort of the basecase scenario. Assuming that the variation in the historic record continues to control the probability distributions in the future.

MR. SEZGEN: Thank you.

DR. JASKE: You're welcome. Other questions? On the phone?

Okay, let me move back where I was, and I'll wind up with these last two chapters.

Limitations. So chapter 9 of the report is a words-only discussion of the limitations that the team believes the report has, the study has.

They are things having to do with how it was designed from the beginning. And then a set of things having to do with the assumptions used in the modeling process.

So, for example, a design limitation. This is done from the physical perspective. We are not characterizing loads or resources for individual load-serving entities, and therefore one cannot extract from this report anything directly applicable to any individual load-serving entity.

There clearly notions of what broad policy pursuit by groups of LSEs might mean in terms of these sort of aggregated results. But can't tell you with much clarity what exactly PG&E

might do in the context of pursuing these assumptions, or Santa Clara.

And with this sort of physical orientation as opposed to an LSE orientation, that's just a feature of the study.

There are things having to do with the data, or the modeling tools, or the uncertainties that are -- and we've talked about many of the limitations in specifics, as I've gone through this earlier parts of this presentation.

But chapter 9, the very first page of that chapter, 2-16 of the report, talks about a little illustration of we've, in the case 5A, found that there's about a $10 a megawatt hour increase in system costs. In return you get, you know, pretty considerable reduction in greenhouse gas that might be a tradeoff that policymakers consider to be appropriate.

There's plenty of uncertainty about whether that $10 a megawatt hour is, you know, really the true penalty. For example, we have not done any independent assessment. And I believe that Itron potential studies haven't made any realistic assessment of how much overhead costs on top of measure costs it would take to actually get to that level of penetration. How much would it take in order for utility programs to get to the level of penetrations of measures that are embodied there.

Or alternatively, you know, would it take mandating those as retrofit on condition of resale or something, in order to cause that degree of penetration.

On the other side it may well be that the costs could go down if technology costs fell relative to what we have assumed.

So there's illustrations right there of two kinds of issues that are jus sort of beyond the ability of this particular study to resolve how changes in those assumptions trace themselves through to the results. And in some respects I'm not even sure there are data out there to help us.

So, the next two slides just very quickly enumerate the little section headings in chapter 9. So, there's a category of efficiency and demand response assumptions that are, clearly we're just taking a best guess in some instances. And especially in the rest-of-WECC efficiency side of things.

The supply side resource additions, I

think we have a reasonably good handle on where those could be located, but we don't have nearly as good a handle on what it takes to actually get them to be built, or at what cost.

We have run into a number of things about the nonpreferred supply side additions, the combined cycles or the coal plants, that lead us to, you know, have uncertainties about their performance through time.

In the modeling area, we have not, at this point, assured ourselves that the kind of modeling we've done addresses local reliability requirements in this aging power plant study that I mentioned earlier. We are attempting to bring that feature to bear, so that when we retire large numbers of those plants we actually can locate dispatchable resources, to the extent they're needed, in the right locations.

I think I've previously mentioned the transmission, both type of them and their costs. There's considerable uncertainty about the attribution of carbon emissions to California imports.

We've used a particular method that's relatively simple. It's difficult to sort of attribute individual power plant to those sort of short-term market purchases, because there's so much flux going on, and it's all a matter of how the model is dispatching resources.

ASSOCIATE MEMBER GEESMAN: Mike, I'm not clear on the retirement scenario. Is that either how you've addressed that across your cases, or what you might do differently to prevent the over-build.

DR. JASKE: Well, now that I see this caption here, I'm not sure why it says completely, because we aren't addressing aging power plant retirements.

ASSOCIATE MEMBER GEESMAN: Taking that word out helps.

DR. JASKE: Because, as I said at some point earlier today, all we're doing is assuming 55-year life. And when it gets to that point it disappears.

ASSOCIATE MEMBER GEESMAN: Okay.

DR. JASKE: What we have in process, and we hope to wind up over the course of the next few weeks is actually looking at the 2005 IEPR policy, identifying the fleets of plants associated with that; retiring them; identifying the replacements that would be necessary.

Doing that individually for the various scenarios so that we can do that replacement in the context of the theme of one of the scenarios. So that a conventional scenario will have conventional replacements. And a high renewable scenario we'll use renewables as much as we can. And then we'll supplement that with something dispatchable in the load center.

That work is still underway, not yet documented or released.

ASSOCIATE MEMBER GEESMAN: Okay. I've got a clear sense of it.

DR. JASKE: Okay. We included the criteria pollutant emissions and were attempting to do the water consumption, but have not paid, you know, much attention to those results. And other than sort of a rough correlation with fuel consumption, I'm not really sure how meaningful they are.

There's a number of feedbacks that this kind of modeling, unless it sort of is done in little sort of piece-wise segments, do a few years, get some results; feed that back into like price effects on customers. I'm not sure how --

which would then change loads and so forth -- how one can fully encompass these sorts of things that are leading to rate impacts, and therefore load impacts, except doing it in that way.

We did not do that. So to the extent that we end up with the prices that ought to be higher because costs are higher, and therefore load should be lower, we haven't really got that kind of thing embodied in these results.

I mentioned earlier today that the resource portfolios aren't optimized. And clearly we're over-built in some respects. We probably could benefit from scaling our efficiency, our renewables in some manner. Either stretching out more in time, or scaling them up and down to fit a little bit better.

We'd, of course, have different results, but the reserve margins would be more in the zone of what was considered acceptable and appropriate.

All of these things collectively, of course, mean these results are indicative, but not indeed ready to believe every megawatt hour or every dollar of cost that we've been reporting.

And there's a lot of uncertainties. I won't go through all of these one-by-one, but clearly the sensitivity assessment that we've been doing is only the tip of the iceberg on this mountain of variables.

Some of this are more important than others, and clearly fuel prices are an important one. We did tackle that in some respects and there is work underway attempting to further understand how, if we have lower UEG consumption, what that might mean for the natural gas market that we hope to report next month. And be a subject of the August 13th workshop.

So, in chapter 10 we sort of catalogue a number of things I've mentioned during the course of the day about possible extensions.

Let me repeat, again, the three things that are delayed, but which are underway. The aging power plant work. This analysis of the impacts of lower power generation consumption on the natural gas market, and particularly on market-clearing prices. And we do hope to actually compute it, bring forward the water consumption consequences of these scenarios.

ASSOCIATE MEMBER GEESMAN: And would that latter consideration be westwide or just in California?

DR. JASKE: We're set up to do it on a westwide basis just assuming generic consumption factors. Sort of like we've done for the criteria pollutants.

It will be more specific to the power plants located in California. We've actually had a small effort by a consultant working with some of our own power plant licensing data to try to get us the nuances, or at least move in the direction of nuances for California power plants.

ASSOCIATE MEMBER GEESMAN: And with respect to coal generation around the west, would the effort attempt to capture a full fuel cycle use of water, or just the generation segment?

DR. JASKE: I believe we're just looking at the generation piece of it.

ASSOCIATE MEMBER GEESMAN: Thanks.

DR. JASKE: And so let me wind up by just referring you to the headings of chapter 10. I don't actually have a slide that lists these.

The first of those is the whole issue of displacing existing coal power plants. There's a host of issues associated with that, some of which we talked about during the course of today. Clearly a major challenge.

The next one has to do with this issue of end effects. And the truncation of the time horizon and the analysis period of 2020. And whether there's ways to better massage the results to reflect the lifetimes of those resources added near the tail end of that period. Levelization does that to some degree, but only imperfectly.

Because of the GHG dimension here, maybe that it's desirable to push out the analysis period to 2025 or 2030 just so we have a better feel for where we're going over the longer haul.

Clearly there are a number of things about the costs and the performance of the various technologies that we can do better on with more time, more effort. That was an issue raised in the January workshop. We're sort of, in some respects here, wringing our hands, you know, that we can't have brought forward to you a more complete assessment of those variations in technology costs over time. But it just was not feasible.

Two other things that are reflected in chapter 10 to some extent. Clearly portions of the coal industry that are taking GHG seriously are looking at various kinds of sequestration technologies.

We could potentially benefit from some examination of that whole issue, of what kind of coal plant. It's clearly not something that we did. Could affect the results in the sense that that might be imperfect, might be improvement upon, you know, a pulverized coal plant without going all the way to no GHG emissions. And so there could be a point at which that kind of technology would be interesting to look at, even though it were not, a nonzero, or a zero emission technology.

And finally, one of the things I mentioned at the very very beginning of this presentation this morning was that we were looking only at the electricity sector. We did not change demand forecasts at all across all of these cases. We did not change them due to any kind of economic demographic changes that might happen from California or the west pursuing some of these things, incurring costs or incurring limitations that might result from other sectors pursuing GHG emission strategies.

Nor did we look at things like electrification that would increase loads, as other sectors might use that as a strategy to deal with their emissions.

So there are plenty of additional things in terms of how just this power generation sector interfaces with the other sectors that are food for much more work going forward.

And with that, I have completed what I have to say for these two chapters. And if there are questions of clarification I'd be happy to try to answer them.

Okay, anything from the audience?

MS. TURNBULL: Jane Turnbull, League of Women Voters. I gather, I'm not exactly sure how to put this, but I'm gathering that this presumes the current structure of the electricity industry. And I'm wondering what, if any, implications there would be if there were increased competition in the industry.

DR. JASKE: Well, I could imagine, first of all, I think yes, this more or less presumes continuation of the industry as-is. However, by being done at a physical level as opposed to a contractual level, I think most of those consequences don't affect the physical system.

It's the contractual load-serving entity who's responsible for what perspective that changes the most in competition models.

That being said, potentially there's different ways in which technologies could be introduced, either faster or slower if there were different, you know, degrees of competition or kinds of competition in the industry. I guess I think of that sort of as a secondary effect.

MS. TURNBULL: But you don't see a change causing significant impacts inevitably?

DR. JASKE: Well, the premise of this set of cases, at least the 3s, 4s and 5s, in effect is that regulatory fiat says certain things happen, whether by legislation or regulatory agency decisionmaking of one kind or another.

So, in a world with perhaps an incentive structure to encourage things to happen, maybe different degrees of competition, you know, would interface more with how that world played out over time.

MS. TURNBULL: Certainly a carbon tax.

DR. JASKE: That's an example.

MS. TURNBULL: Thanks, Mike.

DR. JASKE: But in this particular kind of study I don't think that the degree or types of competition is anything except secondary.

MS. TURNBULL: Thanks.

DR. JASKE: Are there other clarifying questions? Are there any on --

MR. TUTT: I have one, Mike. In terms of the alternative methods for computing carbon emissions, I just want to make sure I understand what you've done there.

Rather than the net system power methodology that we've used, you've separated out contracts and remote resources and attributed specific GHG emissions to those as imports.

And then rather than a Pacific northwest and a southwest signature for the remaining emission, it's rest of WECC all together, is that correct?

DR. JASKE: Yes, that's right. And when we did that, so there's those two changes relative to the net system power approach. When we looked at, and we had computed almost all the scenarios on the basis of the single rest-of-WECC region, we did a test case to segregate the imports into those two, northwest and southwest regions, and re-ran it. And found only about a 4 percent difference.

And so at that point we decided that wasn't worth, you know, re-running all of the previous cases, just to get that small modest change.

PRESIDING MEMBER PFANNENSTIEL: Other questions? Amazing job, Mike. I want to say I think this is really important work, important for the IEPR, but I think important just in terms of how we look at the uncertainties in what we're facing.

The results that you showed us today are incredibly thought provoking, and clearly the beginning of the process. We have another workshop coming up soon. We'll be a little smarter, I think, at that point.

But thank you and the team a lot for the work that we've seen today.

ASSOCIATE MEMBER GEESMAN: Yeah, and I would echo that. And also invite the various parties to comment on our staff work products, to give some thought, not just in this next round of comments, but as we go through the next couple of workshops on these scenarios, whether this is the type of useful tool, which the Committee has hoped that it would be, that the Commission Staff ought to make a more permanent feature of our inhouse capabilities.

I think that we're searching, certainly in response to some of the comments that we got in the 2005 IEPR for analytic processes that can more usefully illuminate some of the choices in front of policymakers. And I think, Mike, you've taken a big step in the right direction here today.

DR. JASKE: Well, as I said earlier this morning, this was only possible with a big team of people and a number of them are here today. Rich came up and answered a question or two. And without both the staff and the contractor we wouldn't be here today.

PRESIDING MEMBER PFANNENSTIEL: Great work. If there's nothing else, we'll be adjourned.

(Whereupon, at 2:35 p.m., the Committee workshop was adjourned.)

--o0o--

CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Committee Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 8th day of July, 2007.